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VISCOUS FINGERING IN UNCONSOLIDATED CORES

BY

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ABSTRACT

A laboratory study was conducted to examine the effect of viscous and capillary forces on breakthrough oil recovery in an unconsolidated Ottawa silica sand pack. Displacement tests were conducted using distilled water to displace iso-octane and Pembina crude. These test results were scaled using the ratio of viscous to capillary forces (L_t).

Displacement tests conducted on iso-octane ($\mu_o/\mu_w < 1$) resulted in recoveries at breakthrough of around 72 percent oil. Pembina crude ($\mu_o/\mu_w > 1$) had recoveries at breakthrough about 43 percent for the same core and conditions used for iso-octane. Initial water saturations for both systems were not the same and decreased with a change from iso-octane to Pembina crude as the test fluid.

Over the range of the universal rate function studied, it was observed that no viscous fingering occured in the floods conducted on iso-octane. However, as the rate function increased in value there was a decrease in the breakthrough recovery of Pembina crude which was attributed to the formation of water tongues at the flood front (viscous fingering).

During the tests carried out with Pembina crude it appeared that the wettability changed from a water-wet to an oil-wet system. This change was assumed to be a function of the effect of oil composition on the solid-liquid surface and was time dependent.

ACKNOWLEDGEMENTS

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INTRODUCTION

Controlling the displacement of oil by water to achieve the maximum efficient and economic recovery from reservoir sands is a problem of major importance in the oil industry today. In an attempt to explain the increase in recovery observed from the waterflood process, Uren[1] cited a number of parameters which influence the displacement phenomena; these being capillary forces, oil viscosity, interfacial tension, wettability, flow rate and the presence of gas. Dimensional analysis applied to these variables results in normalized scaling functions which may be used to relate the laboratory model to the actual reservoir or prototype.

Figure 1 illustrates the theoretical breakthrough recovery as influenced by the interplay of capillary and viscous forces in a linear horizontal model. Region A to B depicts an increase in oil recovery with an increase in a dimensionless rate function. This increase has been attributed to a decrease in the influence of capillary forces on the recovery process. In the laboratory these forces are observed as the inlet and outlet end effects caused by a discontinuity of the capillary forces across the core ends. As a result of the minimization of these forces at an increased value of the rate function, a region of stabilized recovery is attained (B to C). The phenomenon of bypassing the oil by water, leaving behind isolated pockets of hydrocarbons is termed *viscous fingering*[2] (Figure 2). At point C (Figure 1) the onset of fingering within the porous medium occurs and beyond point D viscous fingering has no additional effect on recovery.

If the onset of fingering could be established, and thereby avoided, then maximum recovery could be obtained by the waterflood. The objective of this study was to establish the magnitude of a scaling factor which might be used to predict the onset of fingering within a porous medium.

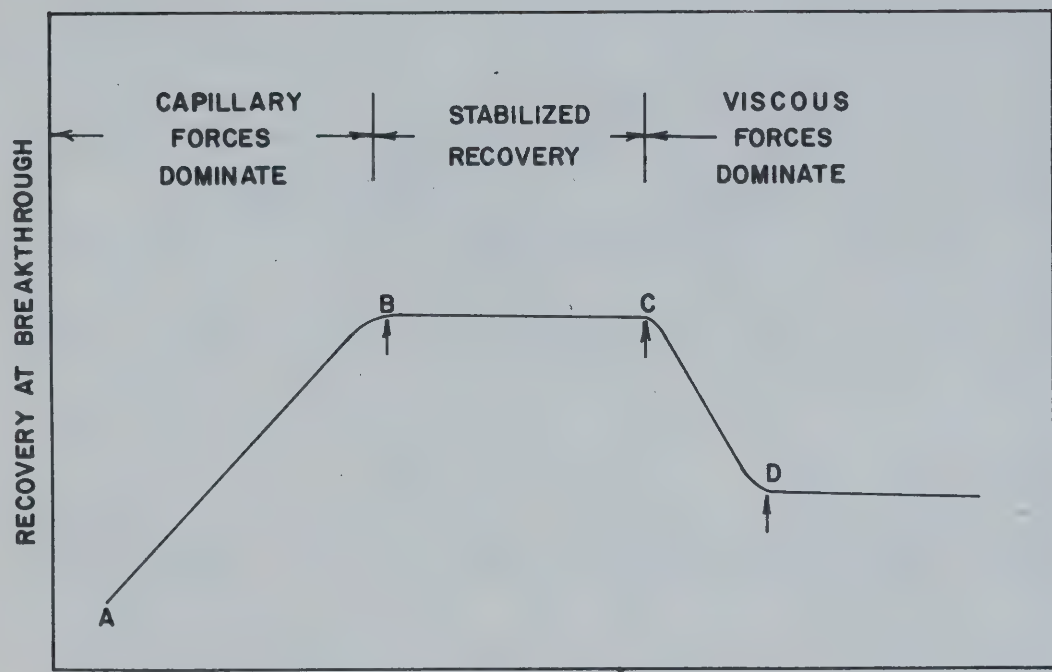

FIGURE 1: GENERAL REPRESENTATION OF BREAKTHROUGH RECOVERY AS A FUNCTION OF RATE (BIBLIOGRAPHY 50)

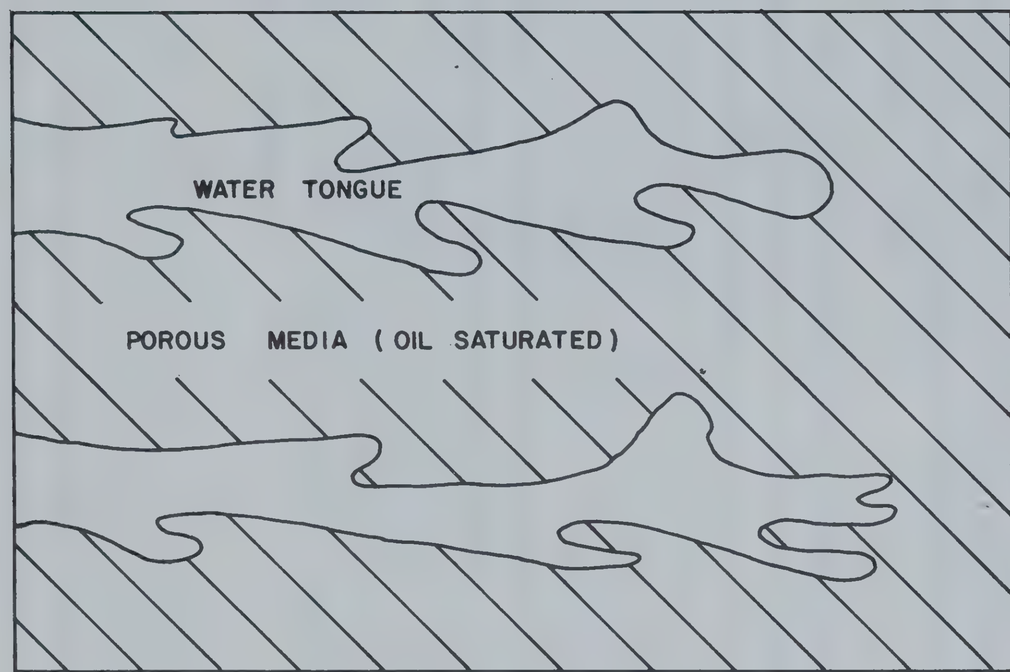

FIGURE 2: VISCOUS FINGERING IN A WATER-WET LINEAR POROUS MEDIUM

LITERATURE REVIEW OF THE PHENOMENON OF VISCOUS FINGERING

Secondary recovery of oil by displacement with water is not a simple straight forward process. It involves a complex displacement phenomenon which is affected by the reservoir rock and fluid properties. The interaction between the capillary and viscous forces is one of the phenomena that must be fully understood and controlled for the attainment of maximum oil recovery.

The influence exerted by these forces on recovery was illustrated in Figure 1. Jones Parra et al[3] and Kyte et al[4] observed that the lower recoveries in the capillary region were due to water fingering at the inlet end of the core, during slow displacement rates. As the waterflood progressed these fingers coalesced into a sharp planar interface. It was, therefore, concluded that a capillary discontinuity across the core end existed, known as the *inlet end effect*, and it was this effect, not the viscous forces, which caused the finger formation. At the outflow end of the sand column there exists a capillary discontinuity. The buildup of a water saturation in the boundary grain layers as a result of the capillary discontinuity decreases the permeability to oil. This laboratory phenomenon is known as the *outlet end effect*. This outlet end effect decreases as the scaling factor increases in magnitude.

Where the driving fluid is more mobile than the driven fluid the interface between the two fluids may become unstable and lead to gross channeling causing a severe decrease in recovery efficiency. It was this observation which prompted Engelberts and Klinkenberg[5] to call this phenomenon *viscous fingering*. In all cases where viscous fingering has been visually observed a marked decrease in recovery was also noted.

A quantitative analysis of fingering was presented by Chouke[6] in 1958. His mathematical method predicts that fingering, due to

viscous forces, will occur if the finger thickness is slightly less than the core diameter. By varying the injection rate, oil-water viscosity ratio and wetting conditions, deHaan[7] experimentally substantiated Choukes theory by showing a marked decrease in recovery at the predicted value for the onset of fingering. By calculating the onset of fingering for the earlier work of Engelberts and Klinkenberg the same observation was possible.

The displacement process is also influenced by the preference of a solid to be wetted by a specific liquid, called the *wettability* of that material. Pirson[8] describes a number of saturation states giving rise to various phases of wettability within the two general categories of water-wet and oil-wet systems.

A porous medium is said to be water-wet if the contact angle, of the water with the oil on the rock surface, as measured through the water phase, is less than 90 degrees and oil-wet if it is greater than 90 degrees. Since wettability is often dependent upon which fluid first contacts the grain surfaces, the majority of reservoirs are water-wet.

> "However, prolonged contact with oil, particularly if the latter contains easily absorbable polar compounds may partially and locally change the wetting properties of a reservoir and give rise to wettability gradients"*

An oil-wet sand is more likely to have less connate water saturation than a water-wet sand due to expulsion of the water as the oil preferentially wets the rock surface. Experimental evidence of deHaan suggests that fingering occurs primarily in water-wet systems with no evidence of water channeling observed in the oil-wet case.

In order to obtain these macroscopic deformations at the stable

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*Pirson, S.J.: "Oil Reservoir Engineering," McGraw Hill, Toronto, (1958), p.69.

interface, force must be applied along the interface. This force acts to overcome the *interfacial tension* which may be defined as the surface energy between a liquid and a liquid or a liquid and a solid. For the water-wet system this force is much less than for the oil-wet system since less energy is required to overcome the interfacial tension between the oil and water than between the oil and rock. This implies that if viscous fingering occurs in the oil-wet medium it would only be manifested at larger throughput rates than in the water-wet case. That is the degree of wettability will affect the viscous fingering phenomena, and such a phenomenon could occur in an oil-wet system contrary to the observations of deHaan.

THEORY OF

IMMISCIBLE OIL-WATER DISPLACEMENT

Displacement of a wetting by a non-wetting fluid, or vice versa, from a linear porous media has been mathematically modelled by a number of researchers. They assume the primary displacement mechanism to be the movement of a steep saturation front through the reservoir followed by an additional gradual oil displacement known as the subordinate phase. These theoretical models have provided a means of predicting the performance behaviour of waterfloods within the limits of the mathematical assumptions.

In 1941 Leverett[9] evaluated Darcy's law within a gravitational field for two liquids, water and oil. By combining these relationships with the formula for capillary pressure:

when $$P_c = P_o - P_w \tag{1}$$

P_c = capillary pressure (atm)

P_o = pressure in the oil phase (atm)

and P_w = pressure in the water phase (atm)

the fractional flow equation was obtained:

$$f_w = \frac{1 + \dfrac{K_o}{q_t \mu_o}\left[\dfrac{\partial P_c}{\partial u} - g\,\Delta\rho\,\sin\alpha\right]}{1 + \dfrac{K_o \mu_w}{K_w \mu_o}} \tag{2}$$

when f_w = fraction of water in the flowing stream at any point

K_o = effective permeability to oil (darcies)

and K_w = effective permeability to water (darcies)

$q_t = q_o + q_w$ = total fluid flow rate per unit cross sectional area (cc/sec/cm^2)

μ_o = viscosity of oil (cp)

μ_w = viscosity of water (cp)

u = flow direction (cm)

g = gravitational constant = 1033 (cm of water/atm)

$\Delta\rho$ = density difference (gm/cc)

and α = angle between u and the horizontal

Later Buckley and Leverett[10] (1942) undertook a theoretical analysis for the displacement of two immiscible fluids. They assumed the gravitational and capillary effects negligible and combined the fractional flow equation with a material balance to yield the frontal advance rate equation:

$$du = \frac{Q_t}{\phi A}\left[\frac{\partial f_w}{\partial S_w}\right] dt \qquad (3)$$

when Q_t = total displacing fluid entering the system (cc/sec)

$\emptyset$ = porosity (fraction of pore volume)

A = cross sectional area (cm^2)

S_w = saturation to water (fraction of pore volume)

and t = time (sec)

This equation relates the linear advance of an interface of constant saturation with an increment of time under the application of a constant fluid injection rate through the porous medium.

Dropping the capillary pressure term lead to a double valued water saturation at the oil-water interface which is a physical impossibility. To overcome this Buckley-Leverett propose a method of balancing areas at the flood front to establish a single sharp interface at the front. Controversy arose over this fact and Douglas et. al.[11] did a numerical integration of the Buckley-Leverett approach with the inclusion of the capillarity and gravity effects. Their results showed only a rounding off of the saturation distribution (Figure 3) at the flood front, the degree of rounding depending on the magnitude of the capillary and gravity forces.

Rapoport and Leas[12] elaborated on the Buckley-Leverett theory describing the transient flow phenomenon in a linear system. Rapoport and Leas assumed incompressible immiscible fluids in the absence of gravity forces and placing the expressions in dimensionless form, Rapoport and Leas solved five simultaneous equations to obtain:

$$\frac{\partial S_w}{\partial T} + \frac{dF}{dS_w}\frac{\partial S_w}{\partial X} - \frac{K}{C_o}\cdot\frac{1}{LV\mu_w}\cdot\frac{\partial}{\partial X}\left[K_{ro}F\,\frac{dP_c}{dS_w}\frac{\partial S_w}{\partial X}\right] = 0 \qquad (4)$$

when $T = tV/L\phi$ = dimensionless time co-ordinate

$F = \left(1 + \frac{K_{ro}}{C_o K_{rw}}\right)^{-1}$ = dimensionless function of saturation

$X = x/L$ = dimensionless space co-ordinate

$C_o = \frac{\mu_o}{\mu_w}$ = dimensionless oil-water viscosity ratio

V = total flow rate per unit cross-sectional area (cm/sec)

and K = specific permeability (darcies)

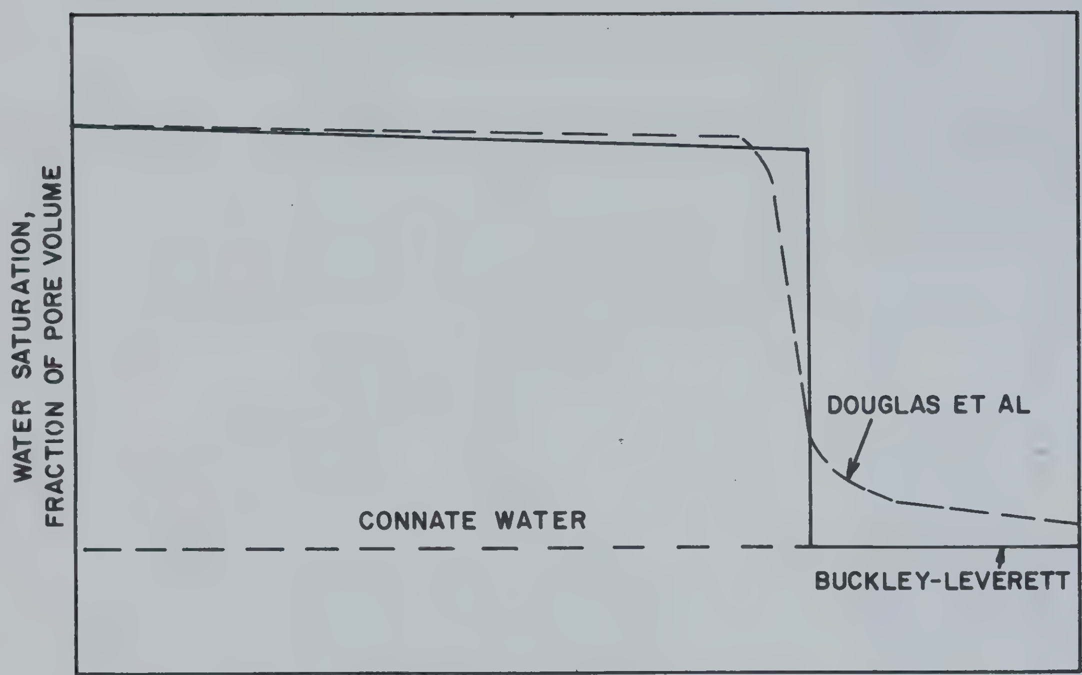

FIGURE 3: FLOOD FRONT SHAPE AS A FUNCTION OF DISTANCE TRAVELED AND WATER SATURATION (REFERENCE 11)

for the boundary condition:

$$K_{ro}\left[1+\frac{K}{LV\mu_w}\cdot K_w\cdot\frac{dP_c}{dS_w}\frac{\partial S_w}{\partial X}\right]=0,\ \text{at } X=0 \text{ for any } T \qquad (5)$$

Equations (4) and (5) supplemented by a statement of the initial saturation distribution completely describes the flooding behaviour in a linear horizontal porous medium. This non-linear parabolic differential equation is not only a function of the rock and fluid properties but also a function of the system length and injection rate as shown by the factor $LV\mu_W$. However this factor does not account for the influence of capillary and wetting forces.

MODEL SCALING

Before an expensive engineering project (such as a waterflood) is undertaken it is advisable to examine the performance of a small scale replica (model) of the reservoir (prototype) whose behaviour is to be studied. Thus it is necessary to define both experimentally and theoretically the extent to which the model is truly an analogy of the prototype. The design of a *dimensionally scaled experiment* or *pure model* that will behave like the prototype involves, in part, the establishment of a number of dimensionless groups relating the various properties of the system.

Rapoport and Leas[13] introduced a scaling coefficient $LV\mu_w$ to study the effect on waterfloods of variations in length, velocity and viscosity. It was found that if the value of $LV\mu_w$ was greater than one, then capillary end effects in the model would be negligible. However, it has been shown[14, 15] that this is not a universal coefficient because it does not account for the capillary forces. Other similar groupings have been proposed in which parameters such as contact angle, porosity, interfacial tension and permeability have been introduced.

A dimensionless scaling factor I was suggested by Engelberts and Klinkenberg[16], deHaan[17] and Collins[18] to scale the ratio of viscous to capillary forces, however, it neglects the contact angle and the porosity.

$$I = \frac{L\ V\ \mu_w}{\gamma\ \sqrt{K}} \qquad (6)$$

I = ratio of viscous to capillary forces

L = total length of the flooded system (cm)

γ = interfacial tension between the oil and water (dynes/cm)

K = absolute permeability (cm^2)

Although I is an useful scaling factor, Geertsma et al[19] showed the group to be a simplification of the universal rate function L_t†:

$$L_t = \frac{L\ V\ \mu_w}{\gamma\ \cos\theta\ \sqrt{K\phi}} \tag{7}$$

θ = contact angle made by the water with the oil on the rock surface

This later group includes the variables of porosity and contact angle which had previously been neglected.

Chuoke et al[20], carried out a theoretical and experimental analysis of fingering. A dimensionless mathematical group was developed which related the average distance between fingers to various properties of the system.

$$\lambda_m = C\sqrt{\frac{\gamma\ K}{V\ (\mu_o - \mu_w)}} \tag{8}$$

λ_m = the average distance between fingers(cm)

The proportionality constant, C, is a dimensionless constant experimentally obtained and was found to have a value of 30 for a system with no connate water present.

The relationship between λ_m and the smallest finger thickness possible at the onset of fingering is given by:

$$\lambda_{cr} = \frac{\lambda_m}{\sqrt{3}} \tag{9}$$

λ_{cr} is called the *critical fingering distance.* The critical fingering distance as a fraction of the tube diameter in a linear flow system was found to be :

$$\frac{\lambda_{cr}}{h} = C\sqrt{\frac{\gamma\ K}{3\ V\ (\mu_o - \mu_w)\ h^2}} \tag{10}$$

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† L_t as given is actually the inverse of what was proposed by Geertsma

h = the diameter of the core (cm)

If λ_{cr}/h is greater than unity no fingering occurs, but if the value is less than one a large number of fingers develop. By solving equation (10) at the onset of fingering ($\lambda_{cr}/h = 1$) the value for C may be calculated.

$$C = \sqrt{\frac{3\ V\ (\mu_o - \mu_w)\ h^2}{\gamma\ K}} \qquad (11)$$

Since the value for C has been found to increase if connate water is present it must be established experimentally for each system.

By solving equation (7) for γ and substituting into equation (10) a relationship between L_t and the critical fingering distance may be obtained:

$$\frac{\lambda_{cr}}{h} = C \sqrt{\frac{3\ L\ \sqrt{K}}{L_t\ \cos\theta\ \sqrt{\phi}\ (\ \mu_o/\mu_w - 1\ )\ h^2}} \qquad (12)$$

and the value of L_t may be calculated at the onset of fingering for each porous medium.

DeHaan, Engelberts and Collins observed a decrease in breakthrough recovery with an increase in the scaling factor once the fingering commenced. By calculating the value of L_t for the point at which fingering occurs ($\lambda_{cr}/h = 1$) from equation(10), it was found to correspond with the point of decreasing recovery with increasing values of the scaling function.

APPARATUS AND MATERIALS

A schematic diagram of the experimental equipment used in this study is shown in Figure 4. The nucleus of the apparatus consisted of a three part core holder into which the test sand was packed. Each core section was of high strength lucite with an inner diameter of 4.08 cm, a 0.635 cm wall thickness and a length of 134.78 cm. These segments met firmly at the mid-point of threaded couplings and were sealed by means of O-rings and high vacuum silica grease. The total length of the core could be varied by attaching or disconnecting sections of the flow tube. The optical properties of the lucite ensured visual observation of the flood front.

Each end of the core was fitted with a lucite cap or endplate (Figure 5) that had a recessed interior and a threaded wall inset with O-rings. The cap accommadated a spreader plate to disperse the fluid and a 200 mesh stainless steel screen to contain the sand.

Two brass electrodes located directly behind the concentrating plate and wired to an electronic relay, timer and an electric bell were employed to detect water breakthrough at the outlet end of the core. Upon completion of the electrical circuit by the water, the bell and timer were triggered.

Pressure taps were installed just beyond the endplates and connections made to a Validyne transducer, Whittaker carrier demodulator and an Advance digital multimeter recorder. High strength copper or stainless steel tubing at the inlet and outlet end carried liquid and gas to and from the core. The core assembly rested on a steel stand and the angle of dip for the core could be set by varying the height of the system at the downstream end.

Imbibition tests were conducted with an apparatus similar to the one described by Bobek, Mattax and Denekas[21]. Surface and interfacial tensions were measured with a Cenco DuNouy tensiometer; and

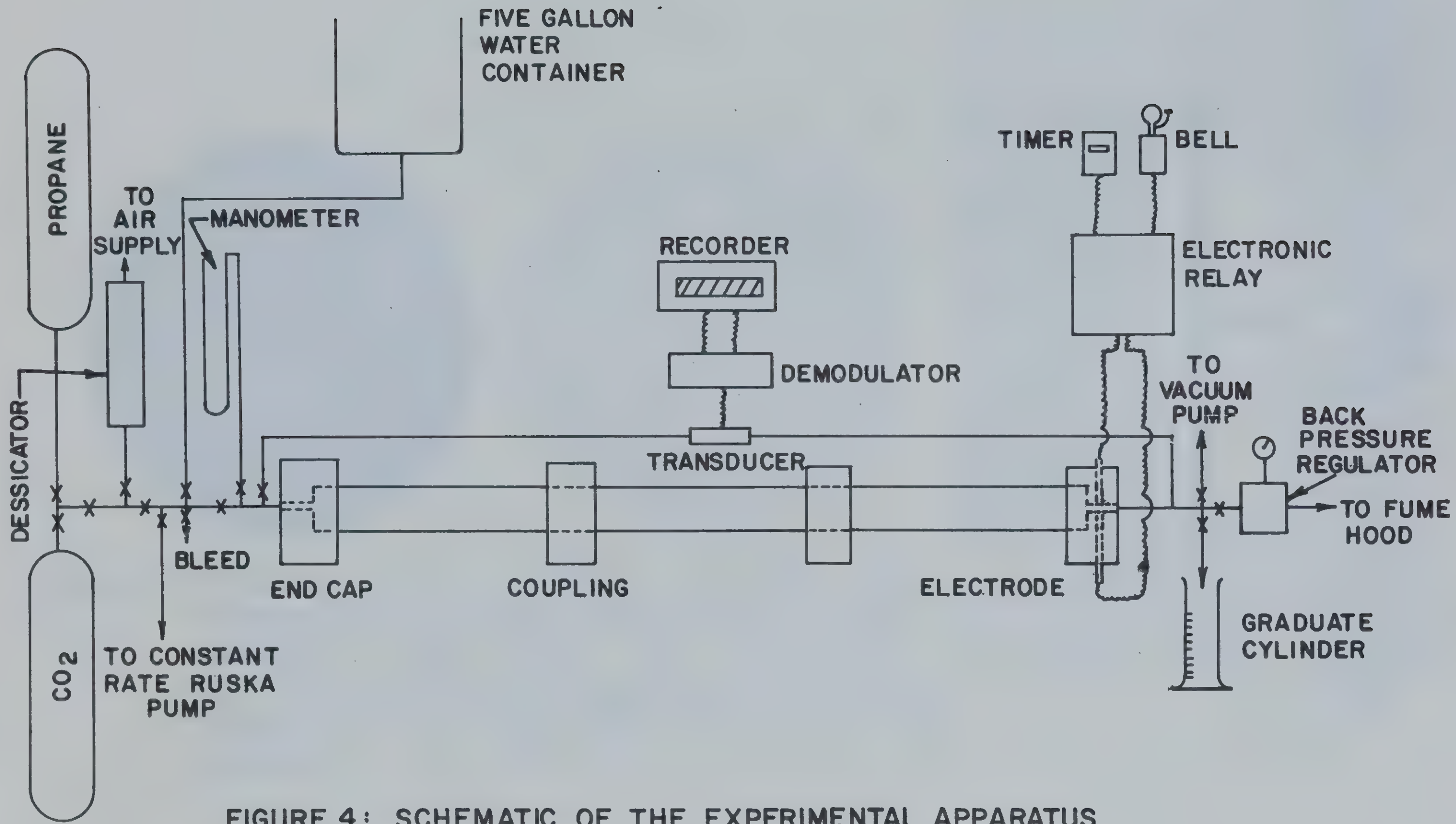

FIGURE 4: SCHEMATIC OF THE EXPERIMENTAL APPARATUS

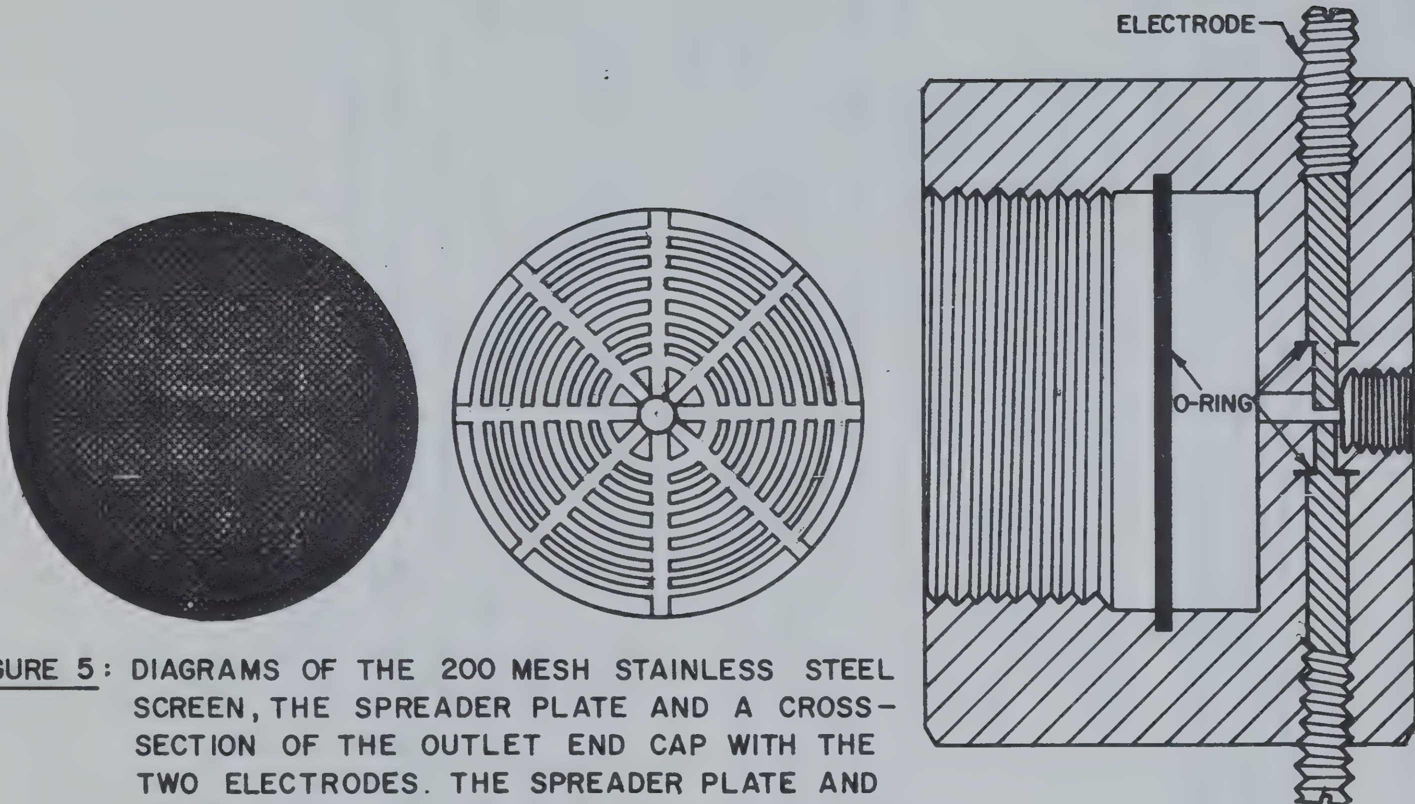

FIGURE 5: DIAGRAMS OF THE 200 MESH STAINLESS STEEL SCREEN, THE SPREADER PLATE AND A CROSS-SECTION OF THE OUTLET END CAP WITH THE TWO ELECTRODES. THE SPREADER PLATE AND SCREEN FIT INTO RECESSED PORTION OF THE END CAP.

the crude oil viscosities were evaluated from measurements obtained with the Bendix Lab Viscometer.

De-aerated distilled water was chosen as the displacing fluid in the waterflood tests. The water was coloured yellow with uranine dye to permit visual observation of the displacement front. Uranine dye was selected because:

1. No reaction takes place between the solute and the grains or the solute and the crude, and
2. The solute imparts flourescent properties to the solvent which facilitates visual and optical observations of the flow behaviour.

Iso-octane and Pembina crude were selected as the oils to be used in the displacement tests. Propane in conjunction with carbon dioxide was used to flush the oils from the core during the cleaning process. A Grove valve and back pressure regulator was attached at the outlet end to hold a back pressure so that propane could be kept in the liquid state.

The test sand was a clean, unconsolidated Ottawa sand (Fisher Scientific S-151) which was passed through an 80 mesh screen and retained by a 120 mesh screen. Examination under a binocular microscope disclosed the sand to be composed almost entirely of sub-rounded quartz grains with minute ferromagnesium impurities. A nearly constant grain size distribution was used to ensure reproducability in repacking different cores.

PROCEDURE

To minimize any possible bypassing at the wall of the lucite, the inner surface of the core barrel was coated with a thin layer of sand. This was accomplished by filling the lucite holder with ethylene dichloride for approximately ten minutes, emptying the fluid and filling the tube with Ottawa silica sand. After approximately two minutes the sand was drained leaving a thin coating of quartz grains on the core barrel wall. It was observed that the lucite developed fine cracks after being exposed to the ethylene dichloride. An examination disclosed the crazing to be only surface deep and therefore would have no effect on the core columns strength.

The sand was packed by agitating the core in a vertical position with high frequency vibrators while the grains fell through a two foot head of water at approximately one centimeter per minute. Vibrators were placed below, above and at the water-sand interface. Following packing, the core was vibrated and flooded simultaneously for a day to check for any sand settlement. The column was then dried by injecting air through the core for three days.

Preceding water saturation of the core, a vacuum corresponding to a 27 inch drop in mercury was pulled on the system. Water was hydrostatically fed into the core until it began producing at the outlet end. The vacuum system was then disengaged and a constant rate Ruska proportioning pump was used to inject water into the core until a steady state flow rate was established at the downstream end. A material balance calculation, based on careful measurements of the inlet and outlet volumes of water, yielded the porosity. Next, pressure drops were recorded at different flow rates and by solving Darcy's law the absolute permeability was calculated. The core fluid was then displaced by oil to an interstitial water saturation before a waterflood was run.

At the outlet end a 2000 cc and twelve 100 cc graduated Kimax

cyclinders were assembled to collect the production of fluids. The larger cyclinder was used to collect oil until water breakthrough and the smaller cyclinders were them employed to collect fluids for the remainder of the waterflood. The 100 cc graduates were changed at specific times and the volume of water and oil in each was recorded. Using the data, the water-oil ratios were calculated.

Before an oil was displaced by water the core was cleaned in the following manner:

1. The sand pack was flushed with liquid propane until no further oil was produced.
2. CO_2 was injected to displace the propane and partially dry the core.
3. Air, fed through a dessicator, was then injected through the core for 2 to 3 days to completely dry it.

Upon the completion of the run #12 one third of the core was removed and experiments conducted on the remainder of the model to check the effects of length on recovery. The segment of the column removed was repacked with the original sand to examine the reproducability of the initial wetting and recovery conditions in the porous medium.

Imbibition tests were carried out on mini-cores with a length of 3.81 cm and a diameter of 1.53 cm. The cores were placed in a vacuum dessicator and saturated with the desired fluid. Once saturated, the core was placed in the imbibition apparatus, surrounded with the imbibing liquid and left for 24 to 72 hours during which time the fluid imbibed into the sample. Imbibition tests were completed:

1. the original sand saturated with water,
2. the original sand saturated with oil,
3. an oil saturated sand taken from the core after run #12,

4. the sand, in the core after run #12, which had been cleaned, dried and resaturated with oil, and

5. the sand, in the core after run #12, which had been cleaned dried and resaturated with water.

DISCUSSION OF RESULTS

Values of the initial rock and fluid properties (ϕ, K, μ, γ) before a waterflood, were measured by means of preliminary tests (tests conducted prior to oil displacement). Table 1 gives a tabulation of these findings and shall be expanded upon below.

The methods for the evaluation of these parameters have been previously discussed in the section titled "Procedure". The values for the porosities varied from 38.7 to 39.7 percent displaying a deviation from the mean of $\pm$ 0.50 units. This is considered to be an acceptable result well within the range of experimental error.

Permeability was calculated using the classical approach for the evaluation of Darcy's Law. Between run #5 and #6 the core was cleaned and a change in the absolute permeability from 16.8 to 15.2 darcies occurred. This drop was attributed to the incomplete cleaning of the core and/or possible incomplete resaturation with water between runs. Packs for run #15 and #16 yielded slightly lower permeabilities of 15.2 and 14.5 darcies respectively. For these much shorter cores it was postulated that the closer spacing of the three high frequency vibrators lead to a slightly more consolidated pack.

Iso-octane and Pembina crude were found to have viscosities of 0.58 and 5.96 cp respectively at room temperature. Interfacial tensions between each fluid and water at room temperature were 41.55 dynes/cm for iso-octane and 32.92 dynes/cm for Pembina crude. These values were considered to be normal for the above oils.

Table 2 shows a tabulation of the core and fluid characteristics present in the sand pack before and following each waterflood. Iso-octane ($\mu_o/\mu_w < 1$) was the displaced fluid for tests #1 to #5 while the remainder of the tests employed Pembina crude ($\mu_o/\mu_w > 1$). Initial water saturations (S_{wi}) for the iso-octane floods ranged from 26 to 28 percent whereas for the Pembina crude floods initial water saturations

TABLE 1

ROCK AND FLUID PROPERTIES

Run Number	Porosity (% Pore Volume)	Absolute Permeability (darcies)	Viscosity of Oil (cp)	Viscosity Ratio (μ_o/μ_w)	Interfacial Tension (dynes/cm)
1-5	39.7	16.8	0.58	0.61	41.55
6-14	39.7	15.2	5.96	6.41	32.92
15	38.7	15.2	5.96	6.41	32.92
16-17	38.8	14.5	5.96	6.41	32.92

Runs No.1 to No.12 had a core length of 404.34 cm which was decreased to 269.56 cm for runs No.13 and No.14, 137.78 cm for run No.15 and 87.0 cm for runs No.16 and No.17.

TABLE 2

DISPLACEMENT TEST CHARACTERISTICS

Run Number	Core Length (cm)	Initial Water Saturation (%)	Flow Rate (cc/hr)	Velocity $\times 10^3$ (cm/sec)	Permeability to Oil (K_o) (darcies)	Recovery (% I.O.I.P.) Breakthrough	WOR = 6
1	404.34	27	620	8.48	–	72	73
2	404.34	26	623	8.53	–	71	73
3	404.34	26	126	1.73	–	71	72
4	404.34	26	30	0.41	–	66	70
5	404.34	28	1235	16.92	–	74	75
6	404.34	20	637	8.73	5.11	44	53
7	404.34	27	114	1.56	5.05	42	51
8	404.34	24	1245	17.02	4.87	33	44
9	404.34	24	822	11.24	2.73	29	40
10	404.34	22	1032	14.15	2.02	23	34
11	404.34	22	613	8.38	2.08	23	32
12	404.34	22	1080	14.80	2.09	22	31
13	269.56	21	614	8.39	1.66	23	29
14	269.56	22	31	0.42	3.01	31	38
15	137.78	Core broke, was unable to continue the run					
16	87.00	18	1235	16.90	5.09	43	56
17	87.00	16	348	4.77	4.80	39	45

varied from 20 to 27 percent. A decrease in the initial water saturation after changing from a lower viscosity to a higher viscosity oil was also observed by Collins[22].

To test the reproducibility of results, tests #1 and #2 were conducted under similar conditions and yielded breakthrough recoveries of 72 and 71 percent; at a WOR of 6 the oil recoveries were equal at 73 percent. With these findings it was concluded that the results are within experimental error and indicate an acceptable reproducibility of a test. Further information can be obtained on the recovery histories for each run in Appendices B and C. Appendix B gives a tabulation of this data and Appendix C includes a graphical illustration of recovery versus pore volume of water injected.

Figure 6 illustrates the recovery versus pore volume of water injected for typical cases of the two oils employed. Referring to the graphical representation of the recovery history for iso-octane, it may be observed that the production obtained up to breakthrough is 72 percent. After breakthrough subordinate production is almost zero. This result closely agrees with the work of Collins and Rapport et al[23] for similar viscosity oils. The recovery breakthrough constitutes the major fraction of the ultimate oil recovery due to the favourable mobility ratio of the system.

The recovery curve for Pembina crude in Figure 6 illustrates a lower breakthrough recovery of 44 percent but a more significant subordinate production. This is again due to the mobility ratio for the system. The larger viscosity of the Pembina crude leads to a less favourable mobility ratio resulting in a lower breakthrough recovery and greater subordinate production.

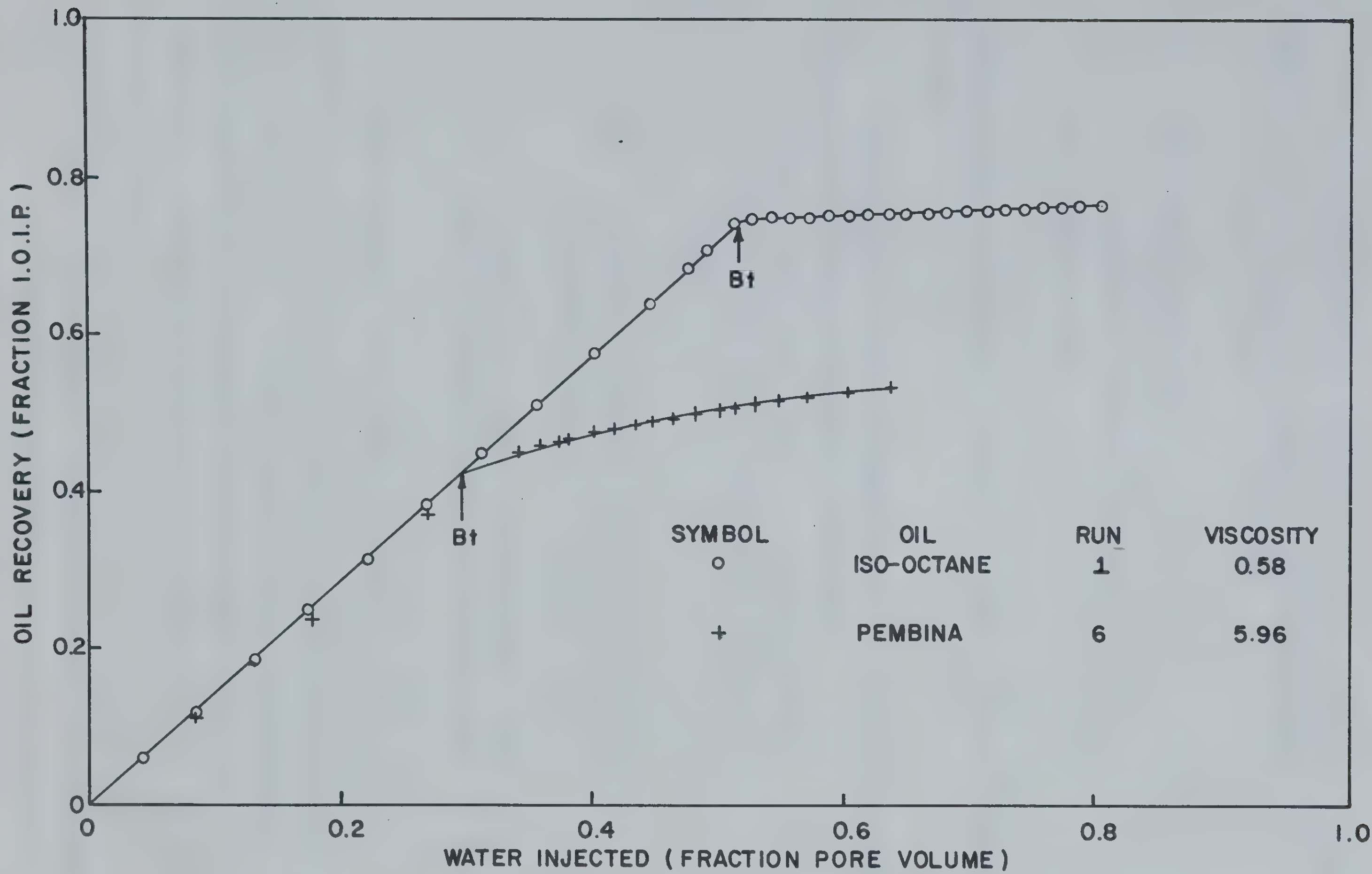

FIGURE 6: RECOVERY HISTORIES FOR ISO-OCTANE AND PEMBINA CRUDE

From the tests it was concluded that the wetting conditions changed in the sand pack while Pembina crude was being used in the core. Three distinct phases were postulated:

i) a water-wet case,

ii) a transition or possibly neutral case and

iii) an oil-wet case.

Justifications for making this deduction are based on the following evidence.

The values of effective permeability to oil (K_o) as tabulated in Table 2 may be divided into three categories.

i) K_o values of 5.0 darcies (runs #6, #7, #8, #16, and #17) were interpreted as the water-wet case,

ii) K_o values of 3.0 darcies (runs #9, and #14) were interpreted as the transition case and

iii) K_o values of 2.0 darcies (run #10, #11, #12 and #13) were interpreted as the oil-wet case.

The Welge Method as outlined in Appendix D was used to calculate the permeability ratios from measured production data. Figure 7 represents the relative permeability curves calculated in the above three cases. The shift in the effective permeability ratio from A to B to C is characteristic of changing wetting conditions. However, one anomalous curve was obtained from run #7. All tests conducted with Pembina Crude had an initial water saturation between 20 to 24 percent except for run #7 which had an initial saturation of 27 percent. Fatt and Klikloff[24] demonstrated that a shift of the relative permeability curve to the left will occur if the porous medium changes from a water-wet to an oil-wet system. However, Stewart[25] in his research found that

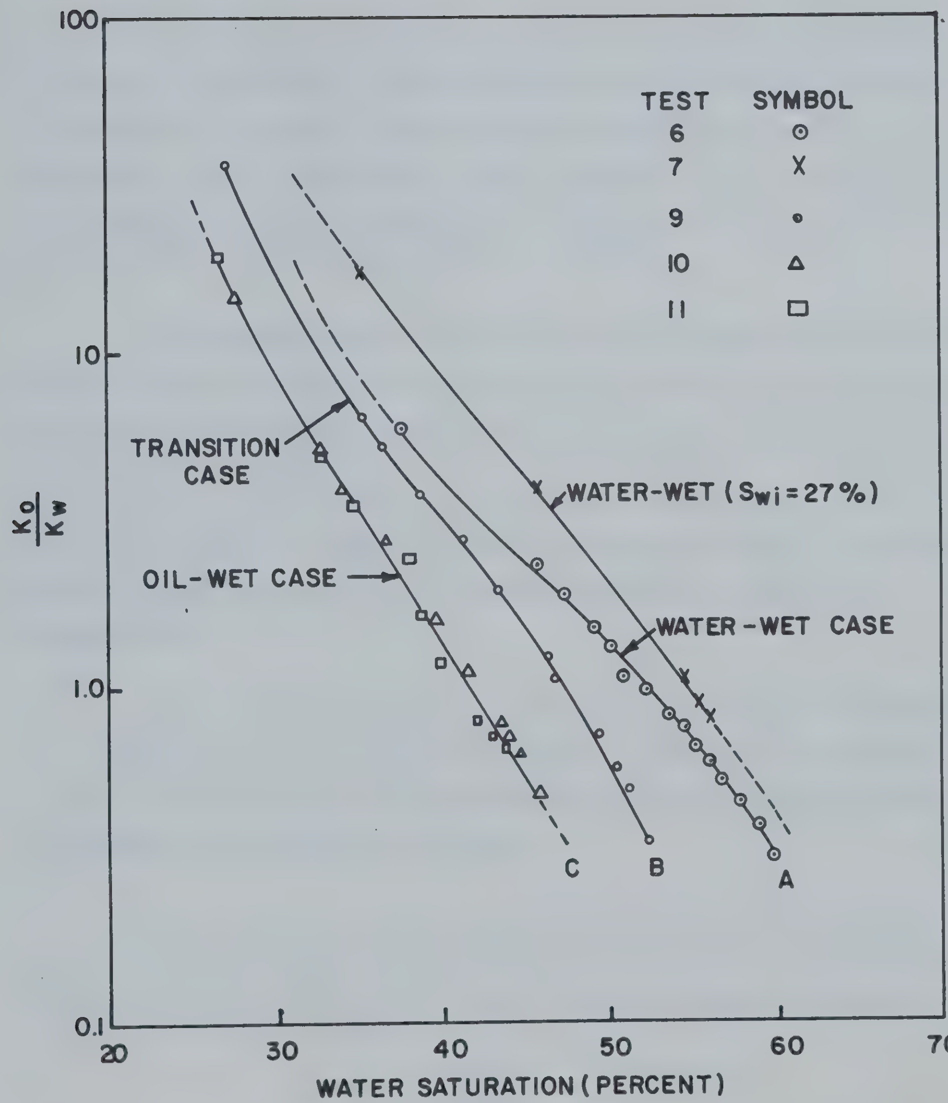

FIGURE 7: RELATIVE PERMEABILITY CURVES FOR THE THREE WETTING CONDITIONS DISPLAYED BY PEMBINA CRUDE.

an increased initial water saturation shifts the relative permeability curve to the right. It was therefore concluded that the anomaly shown for the curve representing run #7 was due to the much higher initial water saturation.

Imbibition tests were conducted on a sample of the original sand and a sample of the sand taken from the core following run #12. A complete description of the results for each test, is given in Appendix A. From these tests it was concluded that the original sand was water-wet and that the sand sample taken from the core after prolonged contact with Pembina crude was oil-wet.

With the exception of run #8 the average breakthrough recovery for the tests conducted where the effective permeability to oil values were around 5.0 darcies, was observed to be about 43%. For runs #10 to #12, where the effective permeability was about 2.0 darcies, the breakthrough recovery was found to be about 22 percent. This trend was also observed by deHaan[26], who had controlled wetting conditions, and is characteristic of the water-wet and the oil-wet cases respectively.

The previous explanations for assuming a change in wettability are by themselves not conclusive. However, when these reasons are taken in conjunction with one another they form a reasonable basis to substantiate the wettability change.

Table 3 gives a tabular representation and Figure 8 is a graphical illustration of the calculated values of I as a function of recovery for the various tests, where I may be found as follows:

$$I = \frac{L\ V\ \mu_w}{\gamma \sqrt{K}} \qquad (6)$$

and L_t:

$$L_t = \frac{L\ V\ \mu_w}{\gamma \cos\theta \sqrt{K\phi}} \qquad (7)$$

TABLE 3

SCALING FACTOR VALUES

Test Number	I (1)	L_t (1)	Breakthrough Recovery (% I.O.I.P.)
1	2.35		72
2	2.35		71
3	0.48		71
4	0.11		66
5	4.64		74
6	2.63	4.82	44
7	0.47	0.86	42
8	5.21	9.54	33
9	3.42		29
10	4.09		23
11	2.44		23
12	0.42		22
13	1.62		23
14	0.08		31
16	1.08	2.01	43
17	0.30	0.56	39

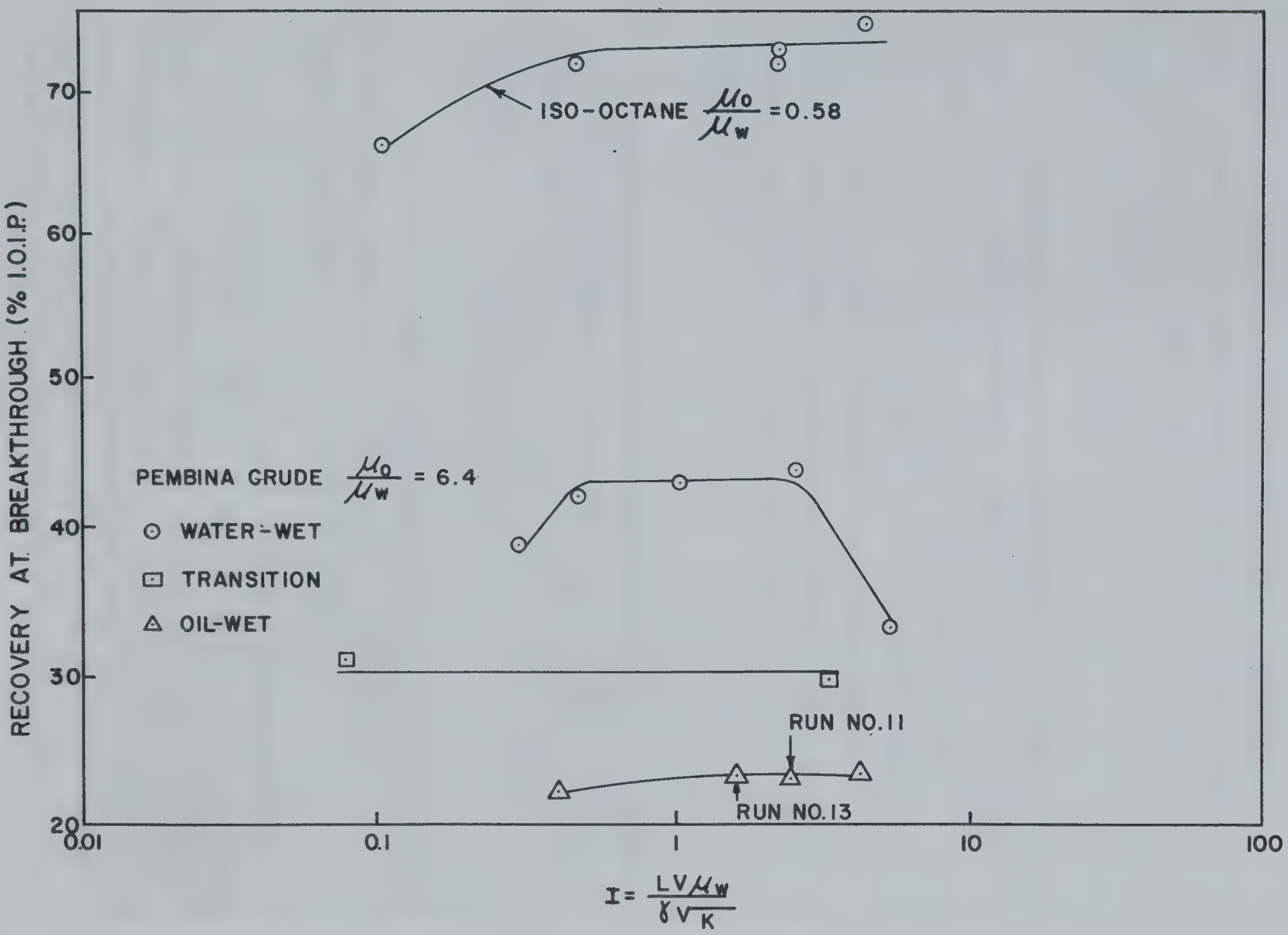

FIGURE 8: RECOVERY VERSUS I FOR ISO-OCTANE AND PEMBINA CRUDE

An examination of Figure 8 shows the recovery of oil at breakthrough (during the waterflooding of iso-octane) increase as the scaling factor increases to a value of about 0.5. Above this value the recovery is fairly constant. The observed decrease in recovery below 0.5 is attributed to the capillary force end effects which play a dominant role at low displacement rates.

The waterfloods conducted on the Pembina crude gave data which resulted in the three breakthrough recovery versus scaling factor relationships shown in Figure 8. For the water-wet case a noticeable decrease in recovery was observed when I exceeded a value of approximately 3.0. Below this value of I, recovery was stable to a value of about 0.5 where a decrease in recovery occurred due to capillary forces. Above a scaling factor value of 3.0 the decrease in recovery is attributed to the onset of viscous fingering of water into the oil which results in isolated oil pockets being left behind the flood front.

The breakthrough recovery for the transition and oil-wet cases, of 30 percent and 23 percent respectively, in Figure 8 was found to be fairly stable over the range of rates studied. However, it is possible that viscous fingering could occur under these wetting conditions for very large throughput rates.

In test #13 the core length was decreased and the flood carried out at the same rate as run #11 (614 cc/hr). The breakthrough recovery in both tests was found to be 23 percent.

When employing the scaling group I it must be remembered that the group is not universal but only a specific form of the L_t function. Figure 9 shows a graphical representation of the studies of Engelberts[27] and deHaan who related the breakthrough recovery to the same scaling group I. By considering the previously mentioned work of Chuoke[28], the onset of fingering was mathematically determined for the work of Engelbert and deHaan. The calculated value of I for $\lambda_{cr}=h$ (the point

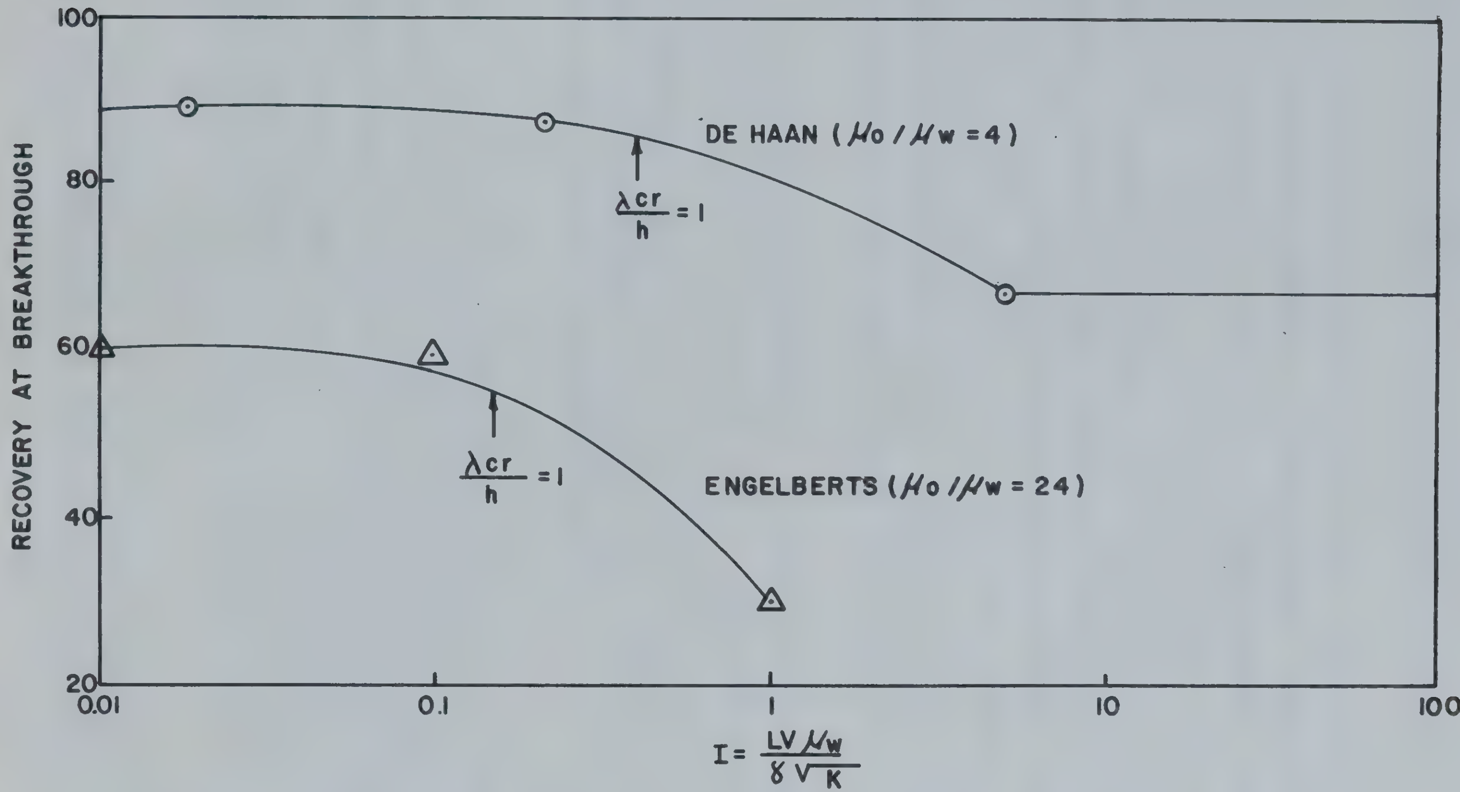

FIGURE 9: COMPARISON OF THE WORK OF DE HAAN AND ENGELBERTS

below which fingering will occur) corresponds to the point of decreasing recovery with increasing I values as shown in Figure 9.

Both Engelberts and deHaan used similar unconsolidated cores in their experimental apparatus. These cores were originally saturated with oil and would only imbibe water to a slight degree. This was referred to by deHaan as an 'intermediate-wet' system. Since their cores were not truly water wet, the contact angle should not be neglected (as deHaan and Engelbert did in evaluating the scaling factor), otherwise a comparison can only be made with another intermediate-wet porous medium. Justification for omitting the porosity, as was done by Engelberts and deHaan, is only valid if the percent pore space in the two systems to be compared is equal. Since the systems of deHaan and Engelberts were nearly identical and experimental conditions were very similar, this may be the reason for their close agreement.

A comparison of Newcombe's[29] and deHaan's work is shown in Figure 10 and a very close agreement exists. This agreement may be attributed to the fact that the contact angle was the same for both cases. Newcombe's experimental procedure for flooding silica sand was the same as that of Engelbert and deHaan. In his work Newcombe showed that the contact angle at breakthrough was 83^o.

For the purpose of comparison with this work, a contact angle of 83^o was assumed for Engelbert's and deHaan's work. It is necessary to assume a suitable contact angle for this study and Collins' work so that all data may be compared using the universal scaling factor L_t. Leach[30] reported a contact angle of 30^o for Berea sandstone for tests conducted under conditions similar to this study and the work of Collins. Therefore, 30^o was used as an approximate value for the water-wet case for these two studies.

The values of L_t for the work of deHaan and Engelberts was calculated assuming a contact angle of 83^o and corresponding porosities of 33 and 38 percent respectively. For the work of Collins and this study a

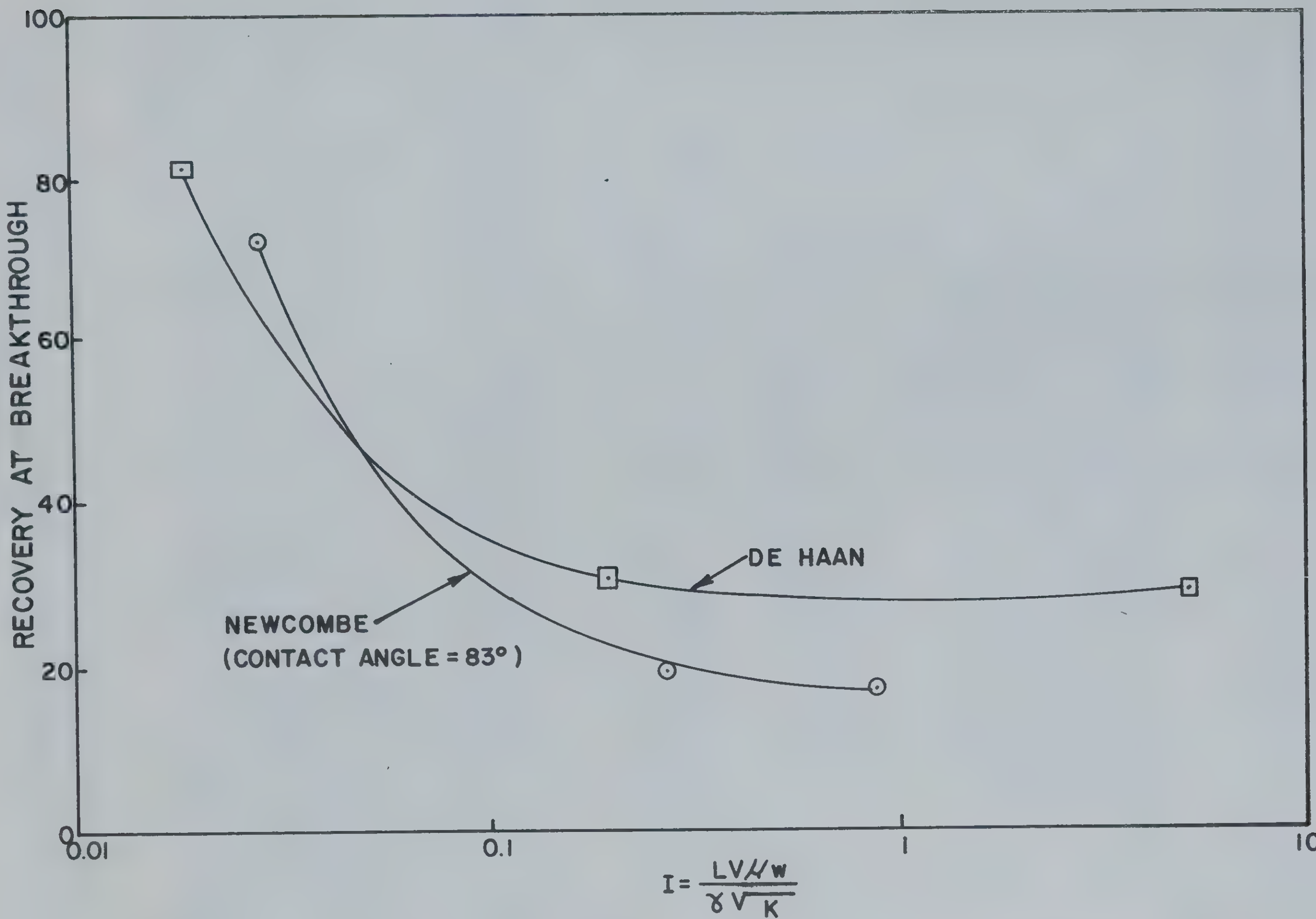

FIGURE 10: COMPARISON OF THE WORK OF DE HAAN AND NEWCOMBE

contact angle of 30^{o} and porosities of 36 and 39 percent were used. Figure 11 illustrates the scaling factor L_t versus breakthrough recovery curves for the above four cases and from these results the following observations were made:

i) For the similar viscosity ratios of this study and the work of deHaan the point where decreasing recovery with increasing L_t values occurs and the calculated values for the initiation of fingering ($\lambda_{cr} = h$) show close agreement to one another.

ii) There is a slight shift of the results to the left of $\lambda_{cr} = h$ for the larger viscosity ratios of Engelberts and Collins.

iii) In all cases the onset of viscous fingering appears to occur at values of L_t greater than 1.0.

It is therefore, safe to assume that no fingering will occur if L_t is less than one in an isotropic homogeneous reservoir as long as the viscosity ratio is not greater than that used by Collins.

The variation of recovery for the four experimental curves shown in Figure 11 is a function of the difference in mobility ratios and the pore geometry for each system. However, due to insufficient information the data is represented in the illustration as a function of the fluid viscosity ratio rather than the mobility ratio.

If a value for the proportionality constant C is known, a value of the scaling factor L_t for the onset of fingering may be evaluated from the following equation:

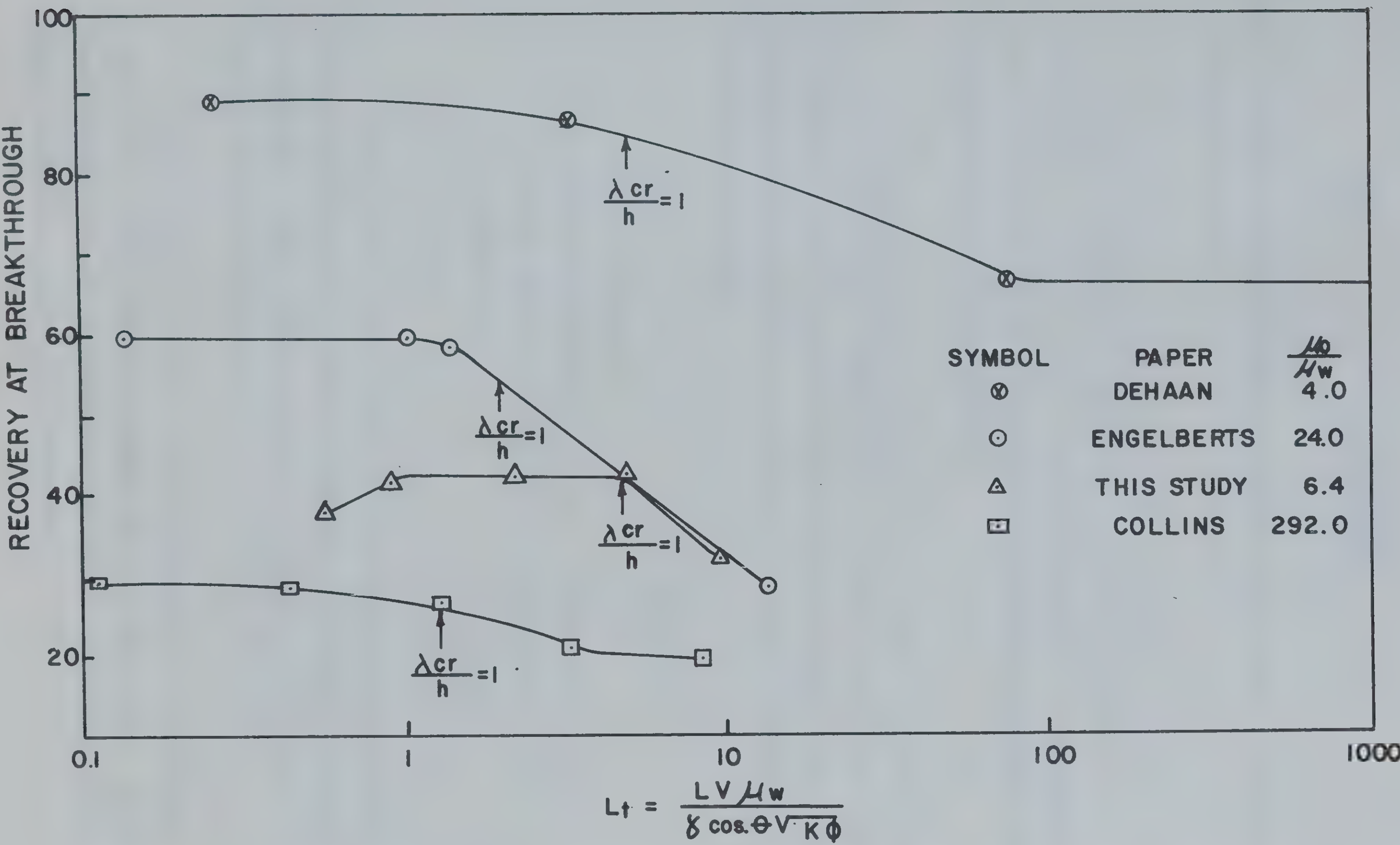

FIGURE 11: COMPARISON OF THE WORK OF DEHAAN, ENGELBERTS, COLLINS AND THIS STUDY

$$\frac{\lambda_{cr}}{h} = 1 = C\sqrt{\frac{3\ L\ \sqrt{K}}{L_t\ \cos\theta\ \sqrt{\phi}\ (\mu_o\ /\mu_w\ -\ 1)\ h^2}} \tag{12}$$

For a porous medium containing no interstitial water C has been found to be equal to 30.

In this work the value of C was calculated to be 64. Hence, for isotropic homogeneous reservoirs, where the value of L, K, contact angle, μ_o, μ_w,h,ϕ and γ can be estimated, an approximate value for velocity of the flood front, beyond which viscous fingering will occur, may be established.

By assuming a linear homogeneous isotropic water-wet porous media having properties similar to the values in the table below, it was found that under reservoir conditions the velocity (V), of the advancing waterfront, must be less than 4.2×10^{-3} ft/day if no fingering is to occur.

Length	300 meters
Water Viscosity	1 cp
Interfacial Tension	30 dynes/cm
Contact Angle	30 degrees
Permeability	100 md
Porosity	30 percent

Once a value of 4.2×10^{-3} ft/day for the flood front advance is exceeded the chances of viscous bypassing are greatly increased. This implies that at least within the vicinity of the injection wellbore fingering may occur due to the high velocities.

In the laboratory it is much more common for the finger height to be greater than the height of the core model. In this case a stable frontal displacement occurs in the model leading to higher recoveries than in the reservoir.

CONCLUSIONS

Based upon this experimental investigation the following conclusions have been reached:

1. For an unconsolidated sand pack exhibiting water-wet conditions the stabilized breakthrough recovery as a percent of the oil in place was 43 percent and 72 percent for viscosity ratios of 6.4 (Pembina crude) and 0.6 (iso-octane) respectively.

2. The adsorption, over a prolonged period of time, of what appeared to be a surface active constituent from the Pembina crude onto unconsolidated quartz grains resulted in a wettability change of the Ottawa silica sand from a water-wet to an oil-wet system.

3. For values of the scaling factor L_t less than one, in a water-wet system, a stable front forms and recovery is essentially independent of a variation in the scaling factor.

4. The value of the proportionality constant C was found to be 64 for the unconsolidated Ottawa silica pack used in this study.

5. Although there are other factors that might effect viscous fingering over the range of rates studied, no fingering occurred when the porous medium was in a neutral or an oil-wet state.

6. When the mobility ratio was less than one (iso-octane) no viscous fingering was observed over the range of the rates studied in this investigation.

RECOMMENDATIONS

To further study the effects of the physical parameters of the scaling factor L_t on oil recovery the following tests are recommended:

i. Use of unconsolidated cores with varying grain size distribution to act as a check on the effects of porosity and permeability and

ii. Conduction of tests on consolidated cores, both homogeneous and heterogenous in nature, to further evaluate the universalism of this scaling group.

With the aid of refined oils of varying viscosities it would be possible to obtain a better understanding of the change in the onset of fingering ($\lambda_{cr} = h$) with oil viscosity. Refined oils would tend to eliminate the wettability change that occurs when using natural crude.

In order to properly evaluate the effect of initial water saturation on the proportionality constant C it is recommended that the initial water saturation be varied on the same test core.

Measurements of contact angles on different rocks for varying oil viscosities would prove invaluable. This would allow future researchers access to a contact angle representative of their system when calculating the onset of viscous fingering.

By flooding the system at different angles of dip the recovery performance and the critical velocity for the onset of water tongues as predicted by Dietz could be compared to the actual measurements. At higher oil viscosities ($\mu_o > 10$) the use of the viscous fingering method of van der Poel and van Meurs versus the Buckley-Leverett theory for predicting performance behaviour could be compared in the region where viscous forces play a dominant role.

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APPENDIX A

LIQUID AND CORE PROPERTIES

LIQUID AND CORE PROPERTIES

In order to establish the surface and interfacial tension of water, Iso-octane and Pembina Crude ten readings were taken on the duNouy tensiometer at room temperature. The arithmetic average was then calculated and corrections applied to the mean which yielded the following results:

	SURFACE TENSION (dynes/cm)	INTERFACIAL TENSION BETWEEN OIL AND WATER (dynes/cm)
ISO-OCTANE	19.95	41.55
PEMBINA CRUDE	27.33	32.92
WATER	71.87	—

Viscosities of Iso-octane and Pembina Crude measured with the Bendix Lab Viscometer at room temperature gave results of 0.58 cp and 5.96 cp respectively. The viscosity of distilled water at various temperatures was obtained from Perry "Handbook of Chemical Engineering" and Figure A-1 was constructed.

The core consisted of three pieces of high strength lucite 134.78 cm long and 4.08 cm in diameter. For runs #1 to #12 the core length was 404.34 cm long. During runs #13 and #14 the length was reduced to 269.56 cm and for run #16 and #17 the core was 87 cm long.

The porosity was obtained by applying a material balance across the core while the initial saturation was being established. Reproduceability of porosity was satisfactory as shown by the following values which were established after each new sand pack was prepared.

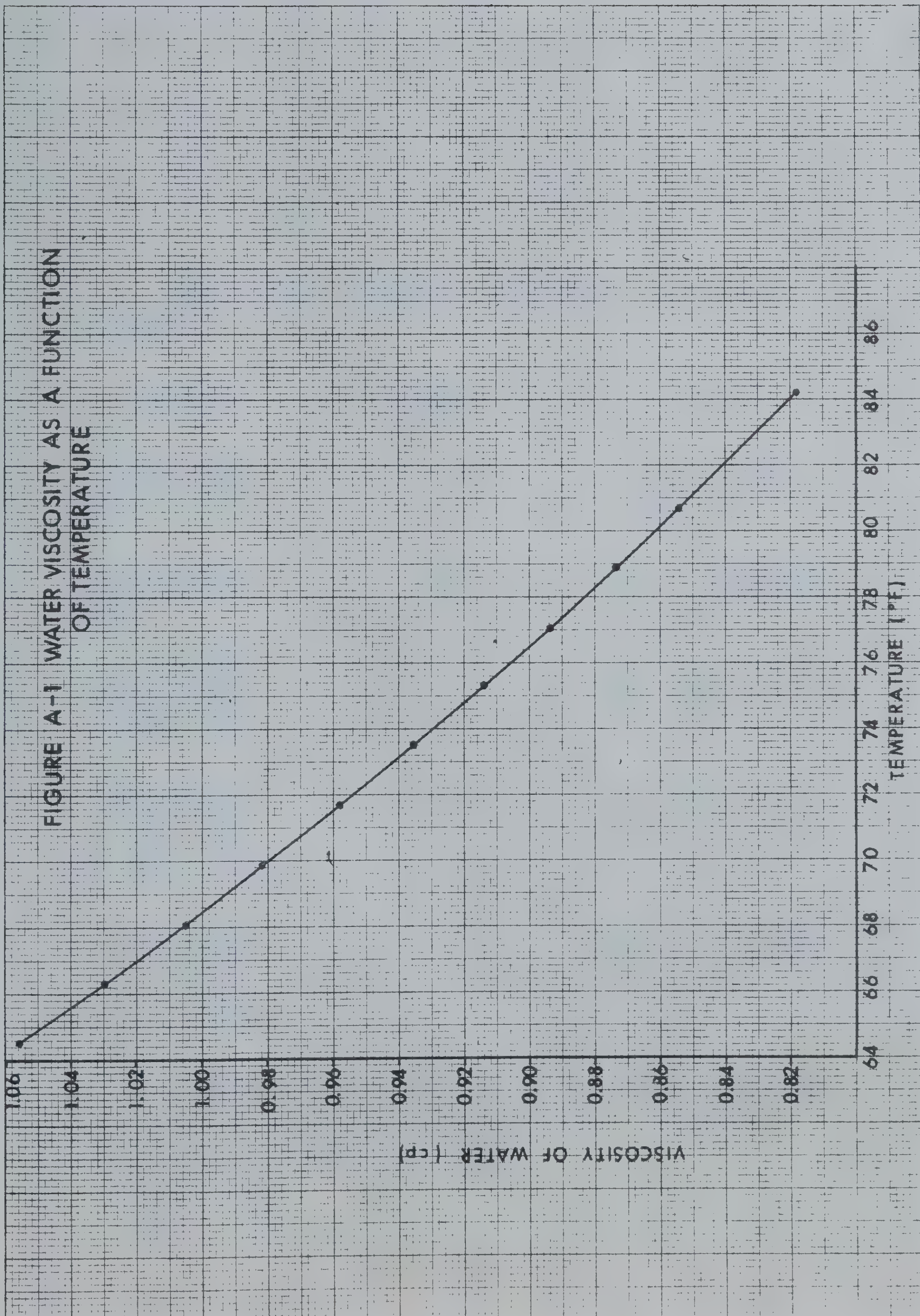


FIGURE A-1 WATER VISCOSITY AS A FUNCTION OF TEMPERATURE

RUN	POROSITY
1	39.7%
15	38.7%
16	38.8%

Imbibition tests conducted on the sand gave the following information:

DESCRIPTION OF SAND	TIME IN IMBIBITION CELL	COMMENT
-original sand saturated with water	24 hours	-no water produced and no imbibition of oil into the core
-original sand saturated with oil	24 hours	-some oil produced and water was found imbibed in the core
-oil saturated sand taken from the core after test #12	48 hours	-no oil was produced and no water was found in the core
-sand taken from the core after test #12 which had been cleaned and saturated with oil	72 hours	-no oil was produced and no water was found to have imbibed into the core
-sand taken from the core after test #12 which had been cleaned and saturated with water	72 hours	-some water was displaced and some oil imbibed into the core

This lead to the conclusion that the sand pack was originally in a water-wet state but due to prolonged exposure to the Pembina Crude changed to an oil-wet condition.

APPENDIX B

DISPLACEMENT TEST RECOVERY DATA

TABLE B-1

DISPLACEMENT TEST RECOVERY DATA - RUN #1

TEMPERATURE = 72° F   BAROMETRIC PRESSURE = 69.8 cm Hg   FLOW RATE = 613 cc/hr S_{wi} = 27%

ISO-COTANE VISCOSITY = 0.58 cp   CORE LENGTH = 404.34 cm   TIME OF FLOOD INITIATION = 0930 hours

TIME (hours)	PRESSURE DROP (psi)	CUMULATIVE OIL PRODUCED (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PRODUCED (cc)	CUMULATIVE WATER PRODUCED (% PORE VOLUME)	WATER OIL RATIO
0945	4.0	140.0	6		4	
1015	4.2	440.0	18		14	
1045	4.6	735.0	31		23	
1115	4.8	1045.0	44		32	
1145	5.1	1345.0	57		41	
1215	5.5	1640.0	69		50	
1222	5.7	1720.0	72		53	
1227	5.7	1729.0	73	29.0	54	3.20
1237	5.7	1735.5	73	123.0	57	30.00
1247	5.7	1737.9	73	223.0	60	44.50
1257	5.7	1739.8	73	324.1	63	54.60
1307	5.7	1741.1	73	424.0	67	81.50
1317	5.7	1742.3	73	526.5	70	84.20
1327	5.7	1743.3	73	627.5	73	107.00
1337	5.7	1744.1	73	723.0	76	112.50
1347	5.7	1744.6	74	824.0	79	252.50
1352	5.7	1744.8	74	875.0	80	255.00

TABLE B-2

DISPLACEMENT TEST RECOVERY DATA - RUN #2

TEMPERATURE = 72° F   BAROMETRIC PRESSURE = 70.2 cm Hg   FLOW RATE = 623 cc/hr S_{wi} = 26%

ISO-OCTANE VISCOSITY = 0.58 cp   CORE LENGTH = 404.34 cm   TIME OF FLOOD INITIATION = 0930 hours

TIME (hours)	PRESSURE DROP (psi)	CUMULATIVE OIL PRODUCED (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PRODUCED (cc)	CUMULATIVE WATER INJECTED (% PORE VOLUME)	WATER OIL RATIO
1000	7.6	240.0	10		7	
1030	7.8	530.0	22		16	
1100	8.0	840.0	35		26	
1130	8.0	1140.0	48		35	
1200	7.6	1450.0	60		45	
1227	7.3	1710.0	71		53	
1232	7.5	1728.0	72	31.5	54	1.80
1237	7.5	1731.0	72	79.5	56	16.00
1247	7.5	1736.0	72	178.0	59	24.80
1257	7.5	1739.5	73	275.0	62	32.60
1307	7.5	1742.0	73	375.0	65	41.70
1317	7.3	1743.9	73	477.0	68	57.80
1327	7.3	1745.5	73	578.0	71	63.80
1337	7.3	1746.6	73	677.4	75	99.00
1347	7.3	1747.3	73	765.4	76	143.30
1357	7.3	1747.7	73	872.4	79	235.00

TABLE B-3

DISPLACEMENT TEST RECOVERY DATA - RUN #3

TEMPERATURE = 72° F   BAROMETRIC PRESSURE = 70.0 cm Hg   FLOW RATE = 126 cc/hr S_{wi} = 27%

ISO-OCTANE VISCOSITY = 0.58 cp   CORE LENGTH = 404.34 cm   TIME OF FLOOD INITIATION = 1935 hours

TIME (hours)	PRESSURE DROP (psi)	CUMULATIVE OIL PRODUCED (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PRODUCED (cc)	CUMULATIVE WATER INJECTED (% PORE VOLUME)	WATER OIL RATIO
2340	2.2	480.0	20		15	
0335	2.2	980.0	41		30	
0715	2.2	1400.0	59		43	
0920	2.0	1645.0	69		51	
0942	2.2	1695.0	71		52	
0952	2.2	1702.0	71	10.0	53	1.40
1002	2.2	1708.5	72	24.5	53	2.20
1012	2.2	1711.9	72	42.3	54	5.20
1022	2.2	1714.4	72	59.8	55	7.00
1032	2.2	1716.0	72	78.8	55	11.90
1042	2.2	1717.0	72	97.8	56	19.00
1053	2.2	1719.2	72	120.7	57	19.10
1102	2.2	1719.8	72	137.2	57	27.50
1112	2.2	1720.1	72	157.2	58	66.70
1122	2.2	1720.2	72	177.2	58	200.00

TABLE B-4

DISPLACEMENT TEST RECOVERY DATA - RUN #4

TEMPERATURE = 74^{o} F   BAROMETRIC PRESSURE = 69.7 cm Hg   FLOW RATE = 30 cc/hr S_{wi} = 27%

ISO-OCTANE VISCOSITY = 0.58 cp   CORE LENGTH = 404.34 cm   TIME OF FLOOD INITIATION = 0200 hours

TIME (hours)	PRESSURE DROP (psi)	CUMULATIVE OIL PRODUCED (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PRODUCED (cc)	CUMULATIVE WATER INJECTED (% PORE VOLUME)	WATER OIL RATIO
0850	1.4	340.0	14		11	
1230	1.4	455.0	19		14	
0830	1.2	1050.0	44		32	
1420	1.2	1225.0	51		38	
2015	1.2	1400.0	59		43	
0200	1.2	1587.0	66		49	
0230	1.2	1597.0	67	5.0	49	0.30
0300	1.2	1604.0	67	13.0	50	1.14
0330	1.2	1608.0	67	23.0	50	2.50
0400	1.2	1612.5	68	33.5	51	2.33
0430	1.2	1617.0	68	44.5	51	2.44
0445	1.2	1619.5	68	50.0	51	2.20
0500	1.2	1621.5	68	55.0	52	2.50
0815	1.2	1645.0	69	132.5	55	3.44
0822	1.2	1647.7	69	142.5	55	4.07

TABLE B-5

DISPLACEMENT TEST RECOVERY DATA - RUN #5

TEMPERATURE = 73° F   BAROMETRIC PRESSURE = 69.6 cm Hg   FLOW RATE = 1235 cc/hr S_{wi} = 28%

ISO-OCTANE VISCOSITY = 0.58 cp   CORE LENGTH = 404.34 cm   TIME OF FLOOD INITIATION = 1407 hours

TIME (hours)	PRESSURE DROP (psi)	CUMULATIVE OIL PRODUCED (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PRODUCED (cc)	CUMULATIVE WATER INJECTED (% PORE VOLUME)	WATER OIL RATIO
1453	15.0	920.0	39		28	
1525	15.0	1585.0	68		49	
1533	15.0	1730.0	74		53	
1538	15.0	1752.0	75	78.0	56	3.50
1544	15.0	1757.0	75	193.0	60	23.00
1549	15.0	1759.0	75	292.0	63	49.50
1554	15.0	1760.2	75	396.0	66	86.70
1559	15.0	1761.2	76	495.0	69	99.00
1604	15.0	1762.0	76	595.0	72	125.00

TABLE B-7

DISPLACEMENT TEST RECOVERY DATA - RUN #7

TEMPERATURE = 72° F   BAROMETRIC PRESSURE = 69.8 cm Hg   FLOW RATE = 114 cc/hr S_{wi} = 27%

PEMBINA CRUDE VISCOSITY = 5.96 cp   CORE LENGTH = 404.34 cm   TIME OF FLOOD INITIATION = 2335 hours

TIME (hours)	PRESSURE DROP (psi)	CUMULATIVE OIL PRODUCED (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PRODUCED (cc)	CUMULATIVE WATER INJECTED (% PORE VOLUME)	WATER OIL RATIO
0430	16.0	460.0	20		14	
0830	12.2	860.0	36		26	
0945	10.1	990.0	42		30	
1000	10.0	1013.0	43	5.0	31	0.22
1015	9.9	1023.0	43	16.5	32	1.15
1030	9.8	1028.5	44	37.5	33	3.82
1045	9.6	1033.5	44	58.5	34	4.20
1100	9.5	1038.0	44	80.5	34	4.89
1115	9.3	1042.5	44	102.0	35	4.78
1130	9.3	1047.5	44	123.5	36	4.30
1200	9.2	1056.0	45	167.0	38	5.12
1245	9.0	1068.5	45	232.0	40	5.20
1330	8.8	1080.5	46	297.0	42	5.58
1415	8.5	1091.0	46	354.0	44	5.43
1500	8.3	1103.0	47	419.0	47	5.42
1545	8.2	1115.0	47	487.0	49	5.67
1630	8.0	1127.0	48	551.0	52	5.33
1718	7.9	1139.0	48	619.0	54	5.67
1945	7.7	1178.0	50	843.0	62	5.74
2220	7.1	1215.5	51	1060.5	70	5.80
0300	7.0	1284.0	54	1530.0	87	6.81

TABLE B-8

DISPLACEMENT TEST RECOVERY DATA - RUN #8

TEMPERATURE = 71° F BAROMETRIC PRESSURE = 70.3 cm Hg FLOW RATE = 1242 cc/hr S_{wi} = 24%

PEMBINA CRUDE VISCOSITY = 5.96 cp CORE LENGTH = 404.34 cm TIME OF FLOOD INITIATION = 828 hours

TIME (hours)	PRESSURE DROP (psi)	CUMULATIVE OIL PRODUCED (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PRODUCED (cc)	CUMULATIVE WATER INJECTED (% PORE VOLUME)	WATER OIL RATIO
845	147.0	220.0	9		7	
904	126.0	740.0	30		23	
907	120.0	810.0	33		25	
912	114.0	861.0	35	21.0	27	0.40
917	108.0	899.5	37	71.5	30	1.33
922	102.5	933.0	38	140.5	33	2.03
927	98.0	962.5	39	212.5	36	2.44
932	94.0	989.0	40	297.5	40	3.21
937	91.0	1009.0	41	373.5	43	3.80
942	89.0	1028.0	42	461.5	46	4.63
947	86.0	1047.0	43	559.5	50	5.16
950	84.0	1056.0	43	611.0	51	5.72
1008	79.0	1104.5	45	923.5	62	6.44
1013	77.5	1116.0	46	1022.5	66	8.61
1018	75.0	1126.0	46	1120.5	69	9.80
1024	75.0	1136.0	46	1231.5	73	11.10
1029	74.0	1145.0	47	1333.0	76	11.28
1035	73.0	1155.0	47	1456.0	80	12.30
1054	71.0	1183.5	48	1815.0	92	12.60

TABLE B-6

DISPLACEMENT TEST RECOVERY DATA - RUN #6

TEMPERATURE = 72° F BAROMETRIC PRESSURE = 70.5 cm Hg FLOW RATE = 637 cc/hr S_{wi} = 20%

PEMBINA CRUDE VISCOSITY = 5.96 cp CORE LENGTH = 404.34 cm TIME OF FLOOD INITIATION = 902 hours

TIME (hours)	PRESSURE DROP (psi)	CUMULATIVE OIL PRODUCED (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PRODUCED (cc)	CUMULATIVE WATER INJECTED (% PORE VOLUME)	WATER OIL RATIO
0930	55.0	280.0	11		9	
1000	48.5	585.0	23		18	
1031	40.0	895.0	35		28	
1055	33.0	1135.0	44		35	
1100	32.5	1156.5	45	27.5	36	1.28
1105	31.8	1172.0	45	64.0	38	2.35
1110	30.0	1185.0	46	109.0	34	3.46
1115	30.4	1193.5	46	139.5	41	3.59
1120	30.3	1203.5	46	181.5	43	4.20
1125	30.0	1214.5	47	223.5	44	3.81
1130	29.5	1225.0	47	263.5	46	3.81
1135	29.0	1235.0	48	304.5	47	4.10
1140	28.5	1245.5	48	347.0	49	4.09
1145	28.2	1256.0	49	393.0	51	4.38
1150	28.0	1265.0	49	430.0	52	4.11
1155	26.0	1273.5	49	472.5	54	5.00
1200	25.5	1282.5	50	525.5	56	4.78
1210	25.0	1295.5	50	595.5	58	5.38
1220	24.2	1309.5	51	682.5	61	6.21
1230	24.0	1324.5	51	777.5	65	6.33

TABLE B-9

DISPLACEMENT TEST RECOVERY DATA - RUN #9

TEMPERATURE = 72^{o} F BAROMETRIC PRESSURE = 70.3 cm Hg FLOW RATE = 821 cc/hr S_{wi} = 24%

PEMBINA CRUDE VISCOSITY = 5.96 cp CORE LENGTH = 404.34 cm TIME OF FLOOD INITIATION = 838 hours

TIME (hours)	PRESSURE DROP (psi)	CUMULATIVE OIL PRODUCED (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PRODUCED (cc)	CUMULATIVE WATER INJECTED (% PORE VOLUME)	WATER OIL RATIO
922	123.0	580.0	23		18	
935	111.0	730.0	29		22	
941	105.0	792.0	32	32.0	25	0.52
948	95.0	837.5	34	93.0	29	1.34
956	93.2	870.0	35	159.5	32	2.05
1004	86.0	899.5	36	244.5	35	2.88
1012	82.0	923.5	37	326.5	38	3.42
1019	80.0	941.5	38	407.5	42	4.50
1027	78.0	959.0	39	497.0	45	5.11
1035	75.0	973.0	39	579.0	48	5.86
1042	73.5	987.5	40	665.0	51	6.88
1049	72.0	999.0	40	751.0	54	7.48
1056	71.0	1009.0	41	837.5	57	8.65
1103	69.8	1018.0	41	923.5	60	9.55
1111	68.5	1025.5	41	1014.0	63	12.06
1118	67.5	1032.0	42	1103.0	66	12.71
1125	66.8	1038.5	42	1193.5	69	13.92
1132	66.0	1044.5	42	1283.5	72	15.00
1139	65.0	1050.5	42	1377.0	75	15.58
1148	64	1056.5	43	1470.5	78	15.58

TABLE B-10

DISPLACEMENT TEST RECOVERY DATA - RUN #10

TEMPERATURE = 74^{o} F   BAROMETRIC PRESSURE = 69.5 cm Hg   FLOW RATE = 1033 cc/hr S_{wi} = 22%

PEMBINA CRUDE VISCOSITY = 5.96 cp   CORE LENGTH = 404.34   TIME OF FLOOD INITIATION = 1550 hours

TIME (hours)	PRESSURE DROP (psi)	CUMULATIVE OIL PRODUCED (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PRODUCED (cc)	CUMULATIVE WATER INJECTED (% PORE VOLUME)	WATER OIL RATIO
1610	189.0	215.0	9		7	
1625	168.0	590.0	23		18	
1632	152.0	647.5	26	38.0	21	0.66
1637	140.0	687.5	27	96.0	24	1.45
1643	134.0	719.5	28	161.0	27	2.03
1649	127.5	747.5	30	235.0	30	2.64
1656	123.5	772.5	31	316.0	34	3.24
1701	119.5	792.5	31	392.0	36	3.90
1706	116.0	809.0	32	469.0	39	4.53
1713	112.0	826.0	33	550.0	42	4.76
1719	108.5	841.0	33	631.0	45	5.40
1724	106.0	854.0	34	716.0	48	6.54
1730	103.5	866.0	34	802.0	51	7.12
1737	101.5	877.0	35	888.5	54	7.86
1741	100.0	887.0	35	974.5	57	8.60
1747	98.0	896.0	35	1061.5	60	9.67
1753	97.0	905.0	36	1148.0	63	9.61
1758	95.2	913.5	36	1233.0	66	10.00
1804	94.0	921.5	36	1317.0	69	10.50
1809	93.0	928.5	37	1409.5	72	13.20

TABLE B-11

DISPLACEMENT TEST RECOVERY DATA - RUN #11

TEMPERATURE = 74° F BAROMETRIC PRESSURE = 69.5 cm Hg FLOW RATE = 612 cc/hr S_{wi} = 22%

PEMBINA CRUDE VISCOSITY = 5.96 cp CORE LENGTH = 404.34 cm TIME OF FLOOD INITIATION = 1317 hours

TIME (hours)	PRESSURE DROP (psi)	CUMULATIVE OIL PRODUCED (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PRODUCED (cc)	CUMULATIVE WATER INJECTED (% PORE VOLUME)	WATER OIL RATIO
1350	120.0	350.0	14		11	
1415	106.0	580.0	23		18	
1425	100.0	625.0	25	64.0	21	0.70
1436	95.0	664.0	26	123.0	24	1.51
1446	91.0	696.5	28	189.0	27	2.03
1455	87.3	722.5	29	264.0	30	2.88
1505	84.2	744.5	30	339.5	33	3.43
1516	81.2	765.0	30	429.5	37	4.39
1526	78.4	781.5	31	510.0	40	4.91
1536	76.0	795.0	32	592.0	43	6.07
1545	75.0	806.0	32	671.5	45	7.23
1555	73.5	817.0	32	780.5	49	8.09
1605	72.0	826.0	33	873.0	52	10.38
1615	70.5	834.5	33	962.5	55	10.47
1625	70.0	842.5	33	1059.5	58	12.19
1635	69.8	850.0	34	1153.0	62	12.46
1644	68.0	856.0	34	1247.0	65	15.67
1655	67.0	862.5	34	1352.0	68	16.67

TABLE B-12

DISPLACEMENT TEST RECOVERY DATA - RUN #12

TEMPERATURE = 74° F BAROMETRIC PRESSURE = 69.9 cm Hg FLOW RATE = 108 cc/hr S_{wi} = 22%

PEMBINA CRUDE VISCOSITY = 5.96 cp CORE LENGTH = 404.34 cm TIME OF FLOOD INITIATION = 845 hours

TIME (hours)	PRESSURE DROP (psi)	CUMULATIVE OIL PRODUCED (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PRODUCED (cc)	CUMULATIVE WATER INJECTED (% PORE VOLUME)	WATER OIL RATIO
1035	38.0	180.0	7		6	
1310	31.8	445.0	18		14	
1430	30.0	560.0	22		17	
1457	29.0	605.0	24	1.0	19	0.02
1545	28.0	704.0	28	4.0	22	0.03
1647	26.0	744.0	29	73.0	25	1.73
1746	25.7	773.0	30	140.0	29	2.41
1808	25.6	781.0	31	169.5	29	3.69

TABLE B-13

DISPLACEMENT TEST RECOVERY DATA - RUN #13

TEMPERATURE = 74^{o} F BAROMETRIC PRESSURE = 70.8 cm Hg FLOW RATE = 612 cc/hr S_{wi} = 21%

PEMBINA CRUDE VISCOSITY = 5.96 cp CORE LENGTH =269.56 TIME OF FLOOD INITIATION = 848 hours

TIME (hours)	PRESSURE DROP (psi)	CUMULATIVE OIL PRODUCED (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PRODUCED (cc)	CUMULATIVE WATER INJECTED (% PORE VOLUME)	WATER OIL RATIO
909	143.0	190.0	11		9	
923	125.5	340.0	20		16	
929	115.0	395.0	23		18	
940	105.0	462.0	27	40.0	23	0.59
949	98.0	487.0	29	116.0	28	3.04
959	92.5	501.0	29	209.0	33	6.64
1009	89.0	511.5	30	301.0	37	8.76
1019	86.0	519.5	30	393.0	42	11.50
1030	83.0	527.0	31	483.5	47	12.07
1041	81.0	533.0	31	579.5	51	16.00
1051	79.0	539.0	32	680.5	56	16.83
1100	79.0	544.5	32	773.0	61	16.90

TABLE B-14

DISPLACEMENT TEST RECOVERY DATA - RUN #14

TEMPERATURE = 76° F　BAROMETRIC PRESSURE = 70.3 cm Hg　FLOW RATE = 31 cc/hr　S_{wi} = 22%

PEMBINA CRUDE VISCOSITY = 5.96 cp　CORE LENGTH = 269.56 cm　TIME OF FLOOD INITIATION = 910 hours

TIME (hours)	PRESSURE DROP (psi)	CUMULATIVE OIL PRODUCED (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PRODUCED (cc)	CUMULATIVE WATER INJECTED (% PORE VOLUME)	WATER OIL RATIO
1019	17.0	49.4	3		2	
1317	16.0	142.9	8		7	
1600	14.5	234.9	14		11	
1833	13.6	313.4	19		14	
2140	13.0	410.4	24		19	
0045	12.7	505.4	30		23	
0125	12.7	526.4	31		24	
0225	12.5	545.4	32	11.0	26	0.58
0325	12.3	554.4	33	32.0	27	2.33
0425	12.1	561.9	33	56.0	29	3.20
0525	12.0	568.4	34	81.0	30	3.84
0825	11.9	586.4	35	154.5	34	4.08
1135	11.9	603.9	36	234.5	39	4.57
1455	11.9	620.9	37	319.5	43	5.00
1640	11.8	629.4	37	366.0	46	5.47
2008	11.8	644.9	38	456.0	51	5.81
2243	11.8	665.4	39	524.5	54	6.52
0117	11.7	664.9	39	594.0	57	7.26

TABLE B-15

DISPLACEMENT TEST RECOVERY DATA - RUN #16

TEMPERATURE = 75° F BAROMETRIC PRESSURE = 68.7 cm Hg FLOW RATE = 1233 cc/hr S_{wi} = 18%

PEMBINA CRUDE VISCOSITY = 5.96 cp CORE LENGTH = 87.0 cm TIME OF FLOOD INITIATION = 1735 hours

TIME (hours)	PRESSURE DROP (psi)	CUMULATIVE OIL PRODUCED (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PRODUCED (cc)	CUMULATIVE WATER INJECTED (% PORE VOLUME)	WATER OIL RATIO
1747	15.0	235.0	42		35	
1751	13.0	287.0	52	46.0	49	0.88
1757	12.0	307.0	56	144.0	67	4.90
1802	11.0	318.0	58	239.0	83	8.64
1808	10.2	326.5	59	329.0	97	10.59
1813	9.8	333.0	60	423.0	112	14.46
1817	9.2	339.0	61	517.0	127	15.66
1823	9.0	345.5	62	610.0	142	14.30
1828	8.8	350.5	63	707.5	157	19.50
1833	8.7	355.0	64	804.5	172	21.56

TABLE B-16

DISPLACEMENT TEST RECOVERY DATA - RUN #17

TEMPERATURE = 75° F   BAROMETRIC PRESSURE = 69.0 cm Hg   FLOW RATE = 348 cc/hr S_{wi} = 16%

PEMBINA CRUDE VISCOSITY = 5.96 cp   CORE LENGTH = 87.0 cm   TIME OF FLOOD INITIATION = 1333 hours

TIME (hours)	PRESSURE DROP (psi)	CUMULATIVE OIL PRODUCED (cc)	CUMULATIVE OIL (% I.O.I.P.)	CUMULATIVE WATER PRODUCED (cc)	CUMULATIVE WATER INJECTED (% PORE VOLUME)	WATER OIL RATIO
1356	13.0	127.0	22		18	
1414	10.0	220.0	39		33	
1433	9.0	246.5	43	71.0	47	2.68
1454	8.5	257.5	45	162.5	62	8.32
1516	8.0	264.0	46	261.5	78	15.23
1534	7.6	270.0	47	358.5	93	16.17
1550	7.4	274.0	48	442.5	106	21.00

APPENDIX C

DISPLACEMENT TEST RECOVERY GRAPHS

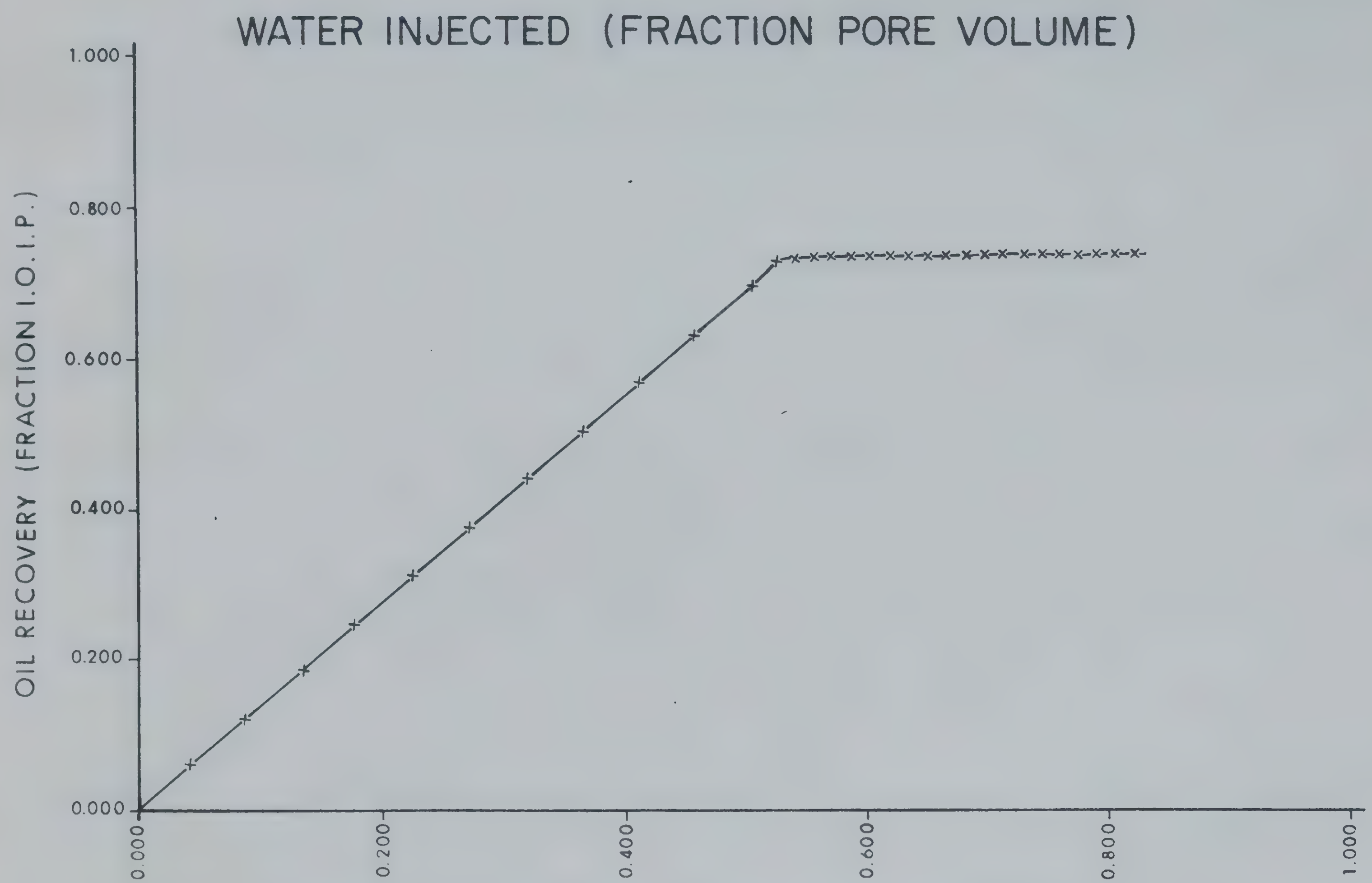


FIGURE C−1 : DISPLACEMENT TEST RECOVERY-RUN No.1

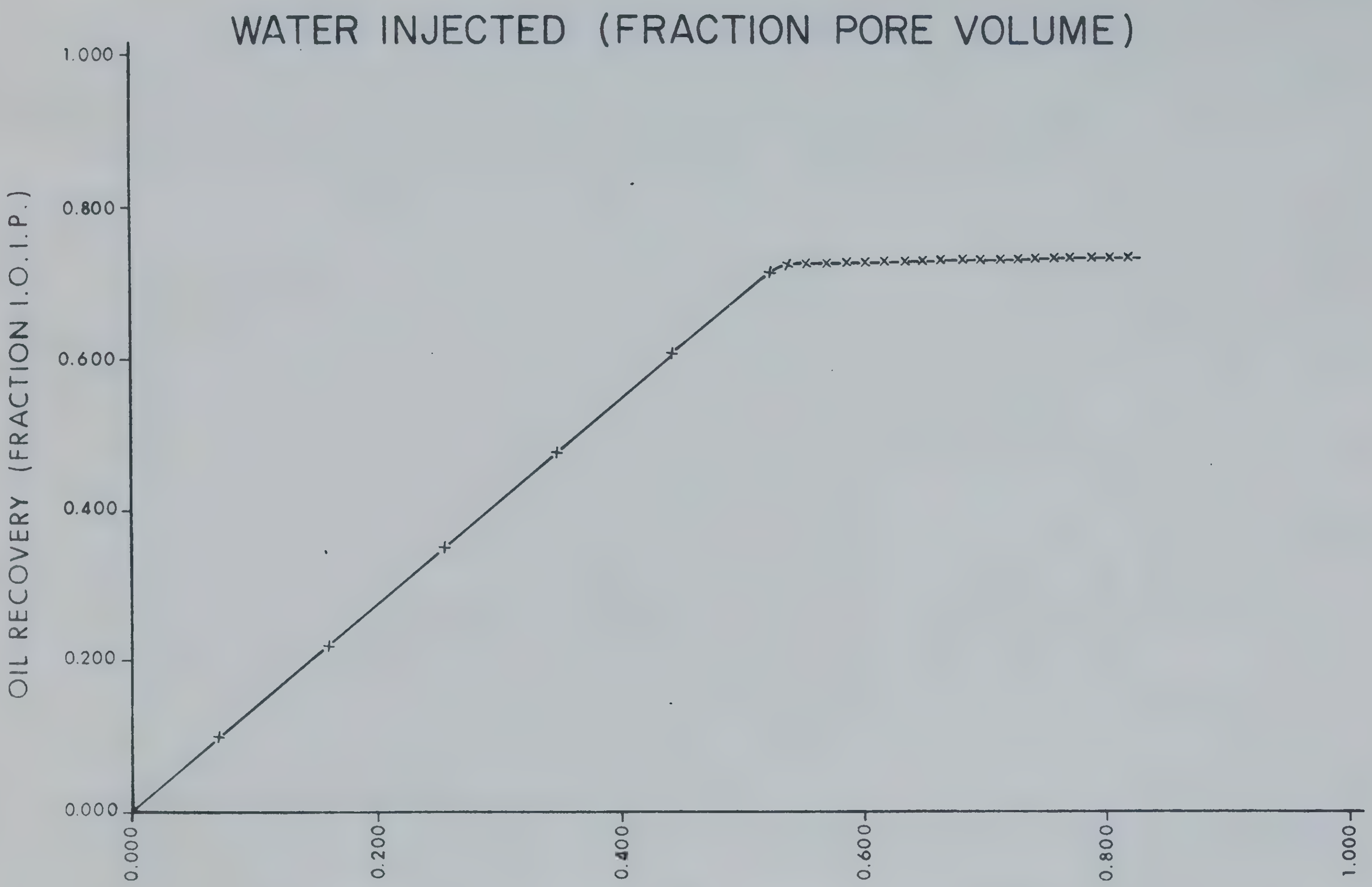


FIGURE C-2 : DISPLACEMENT TEST RECOVERY-RUN No. 2

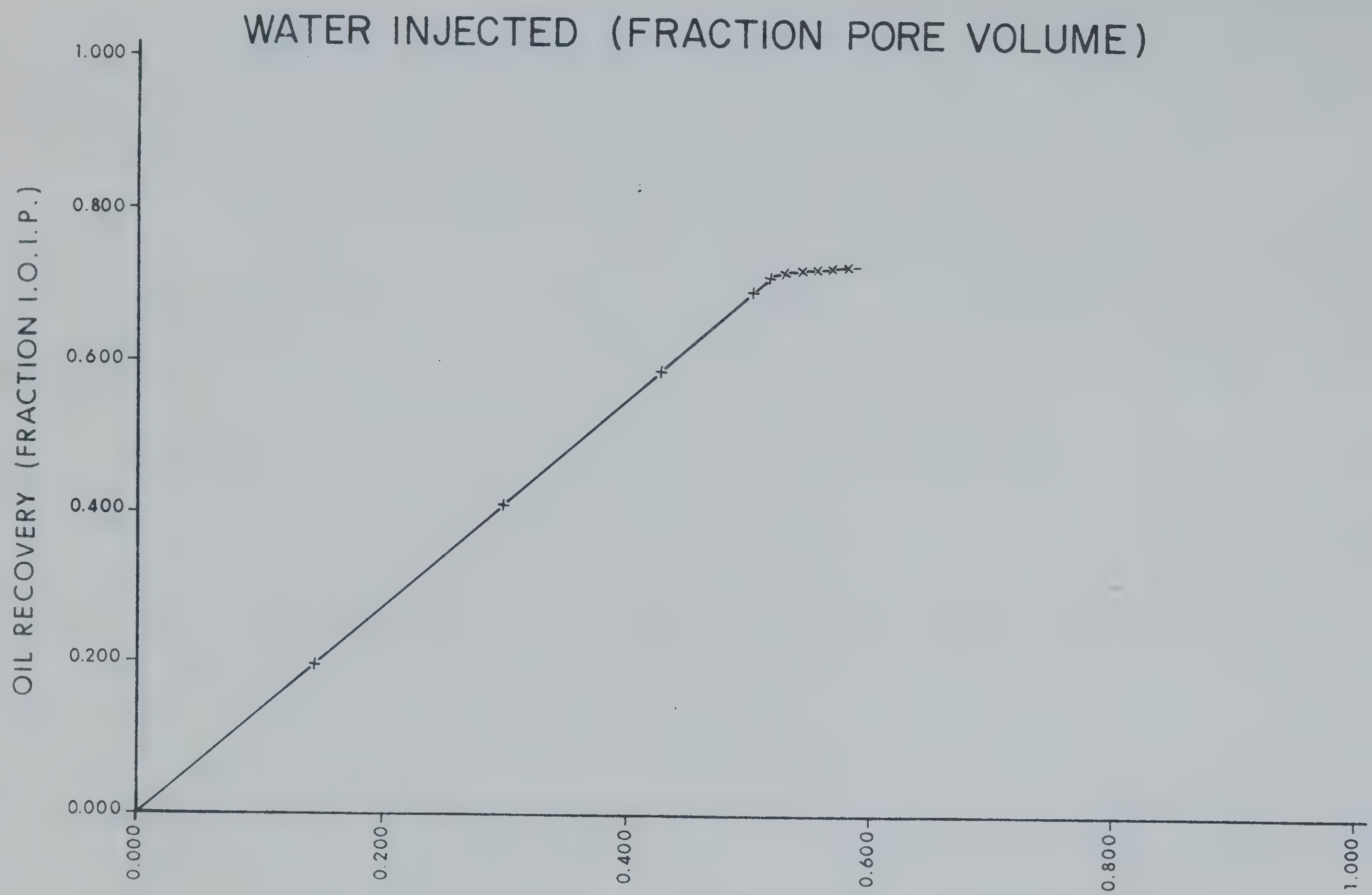


FIGURE C – 3 : DISPLACEMENT TEST RECOVERY-RUN No. 3

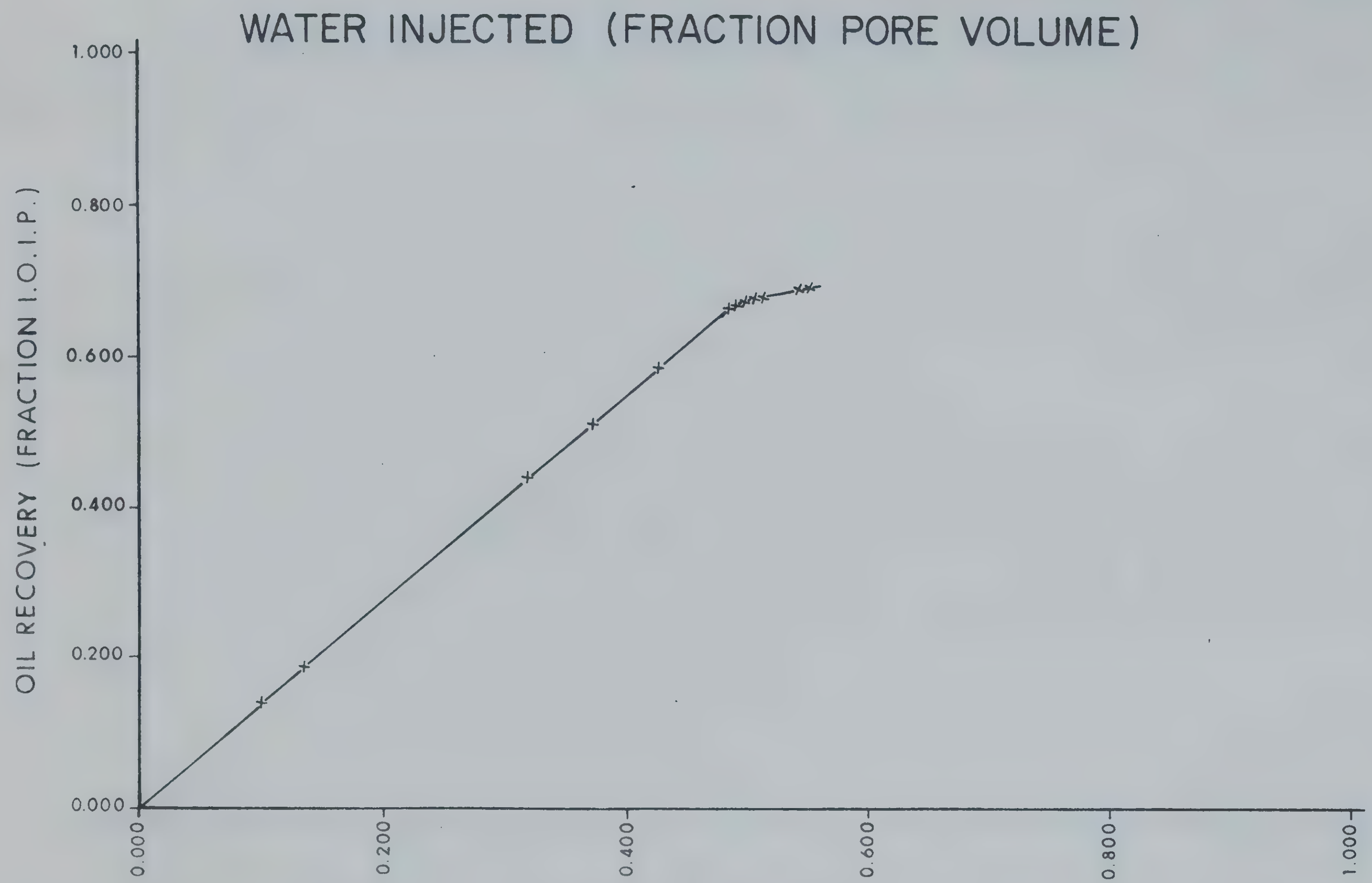


FIGURE C – 4 : DISPLACEMENT TEST RECOVERY–RUN No. 4

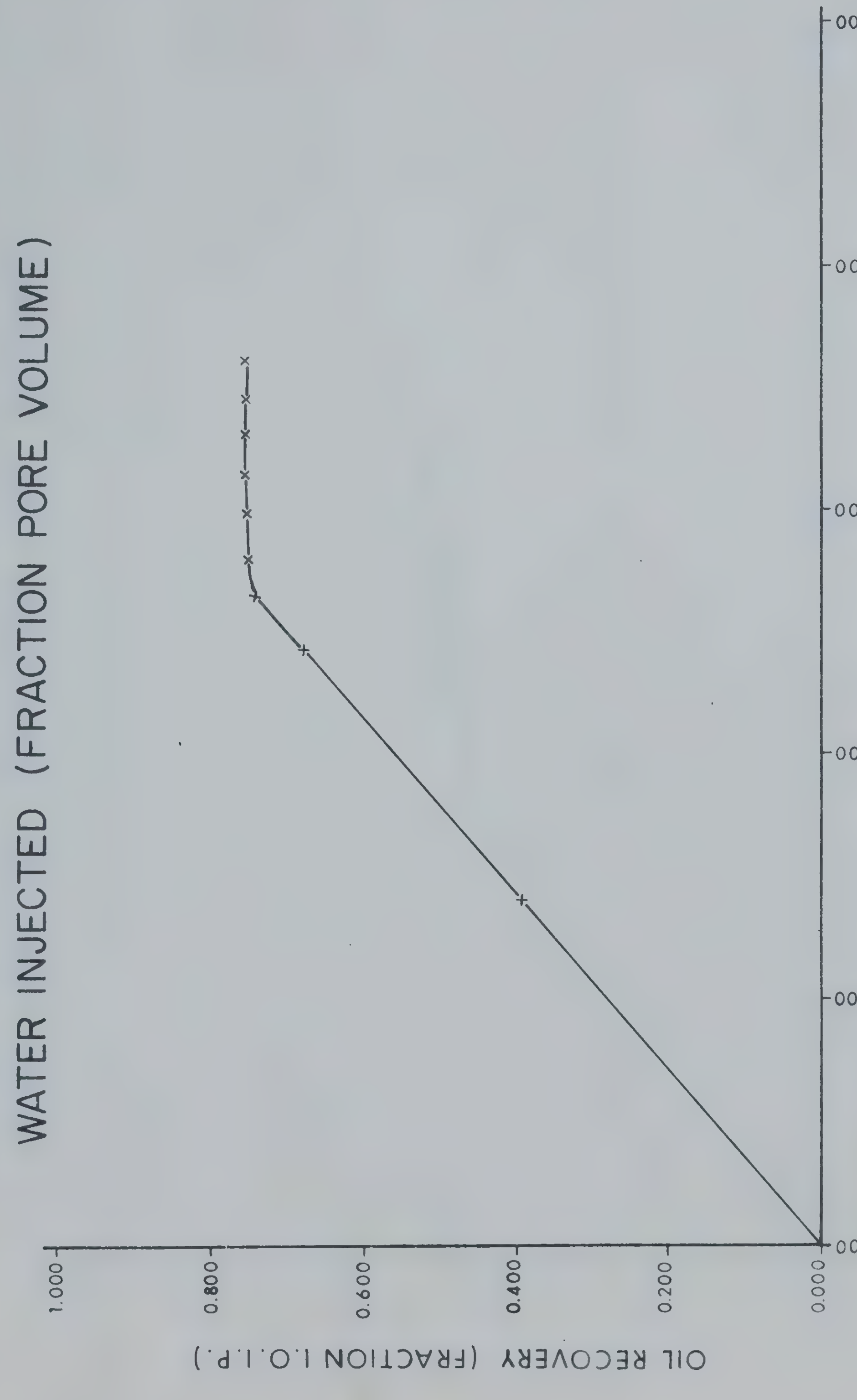


FIGURE C – 5 : DISPLACEMENT TEST RECOVERY-RUN No.5

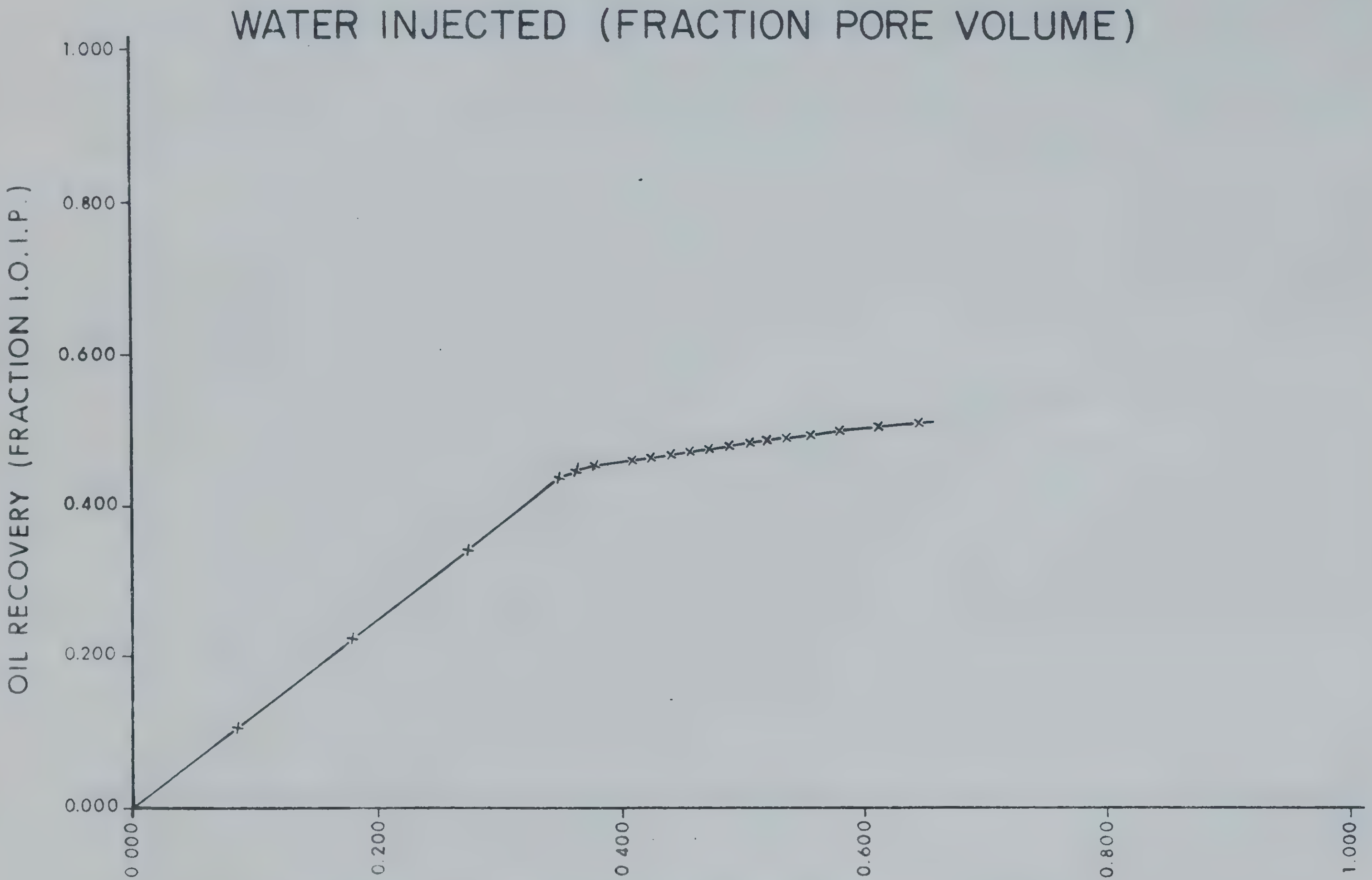


FIGURE C − 6 : DISPLACEMENT TEST RECOVERY–RUN No. 6

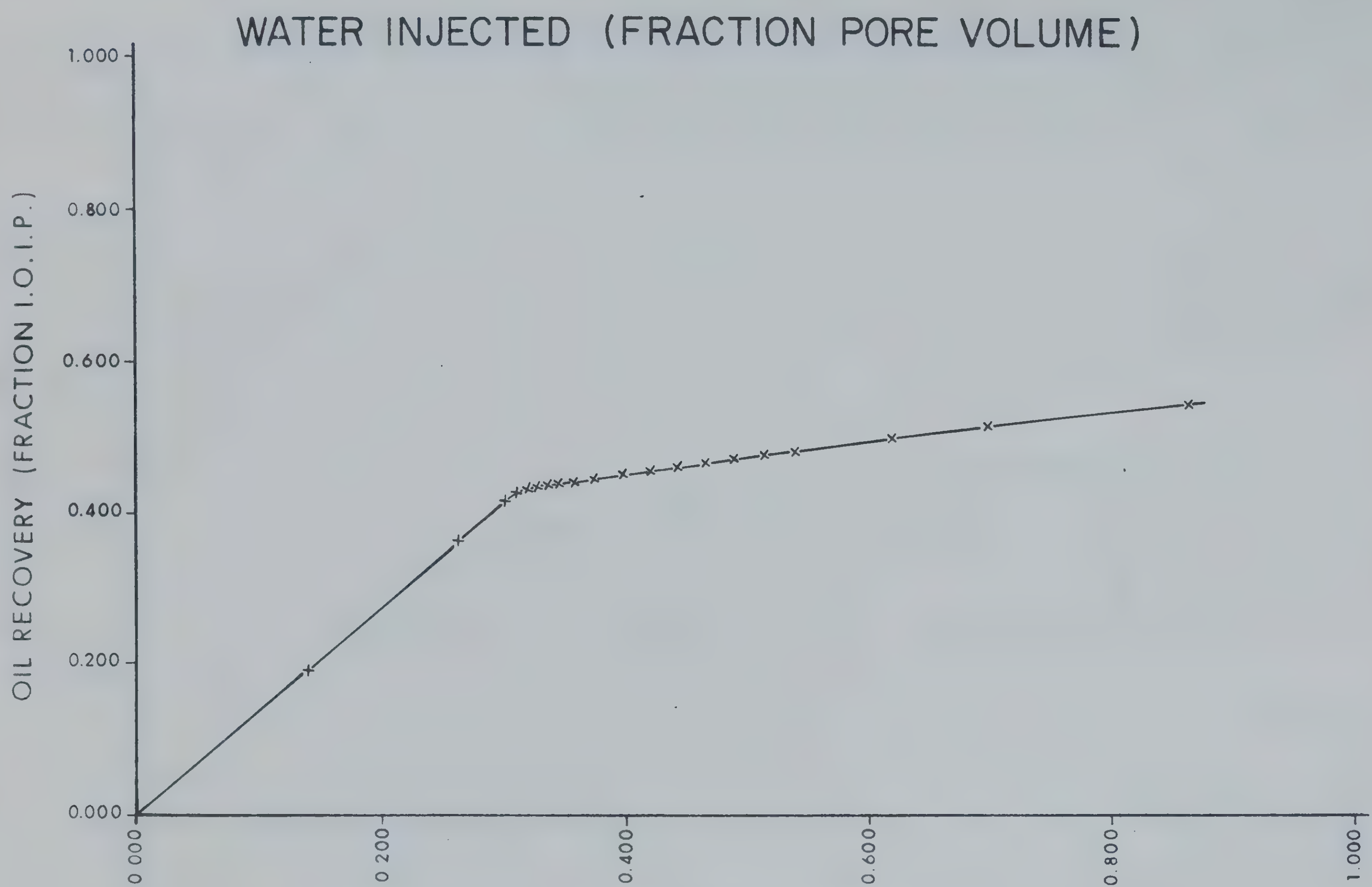


FIGURE C-7 : DISPLACEMENT TEST RECOVERY-RUN No. 7

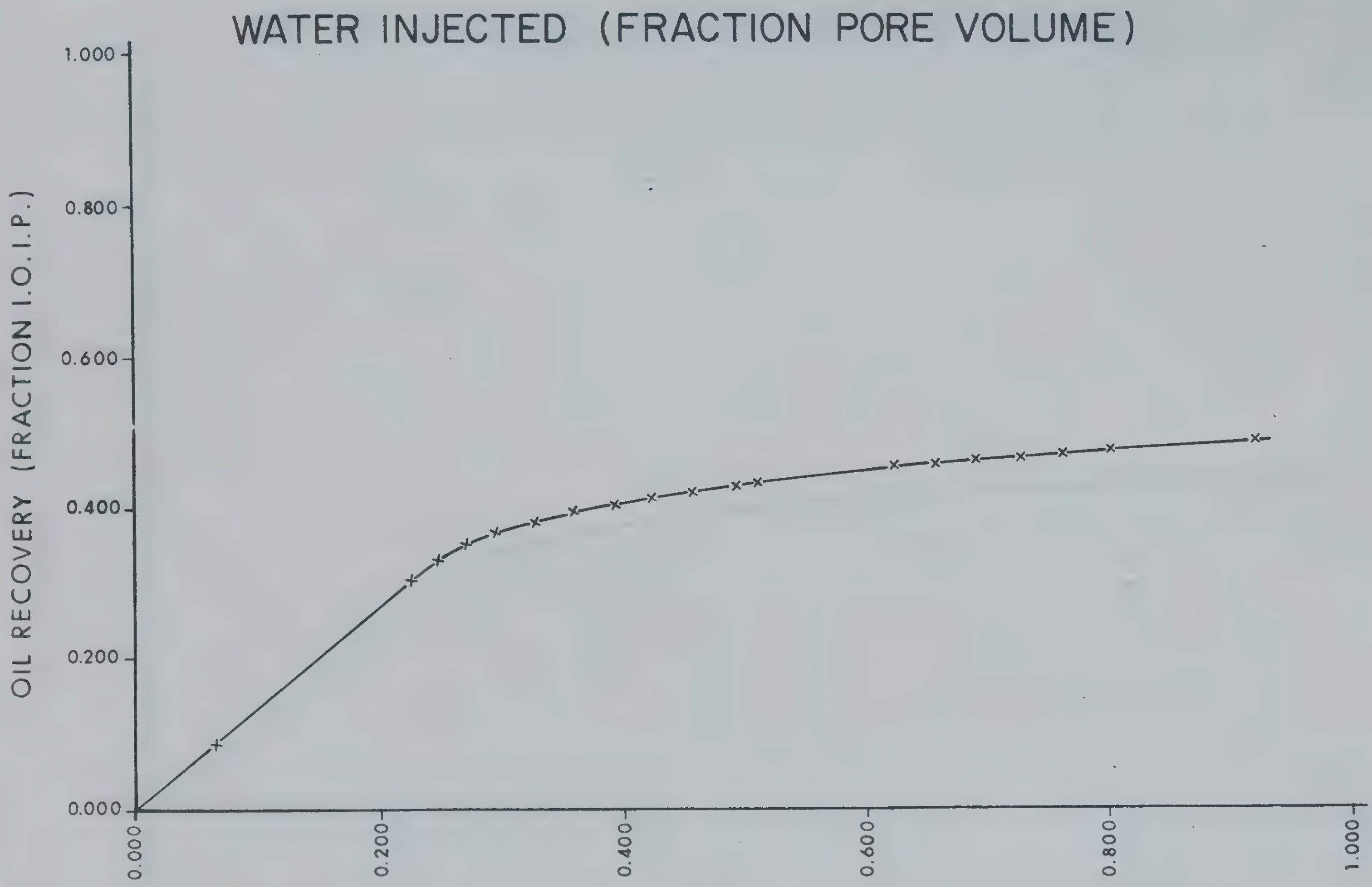


FIGURE C – 8 : DISPLACEMENT TEST RECOVERY–RUN No. 8

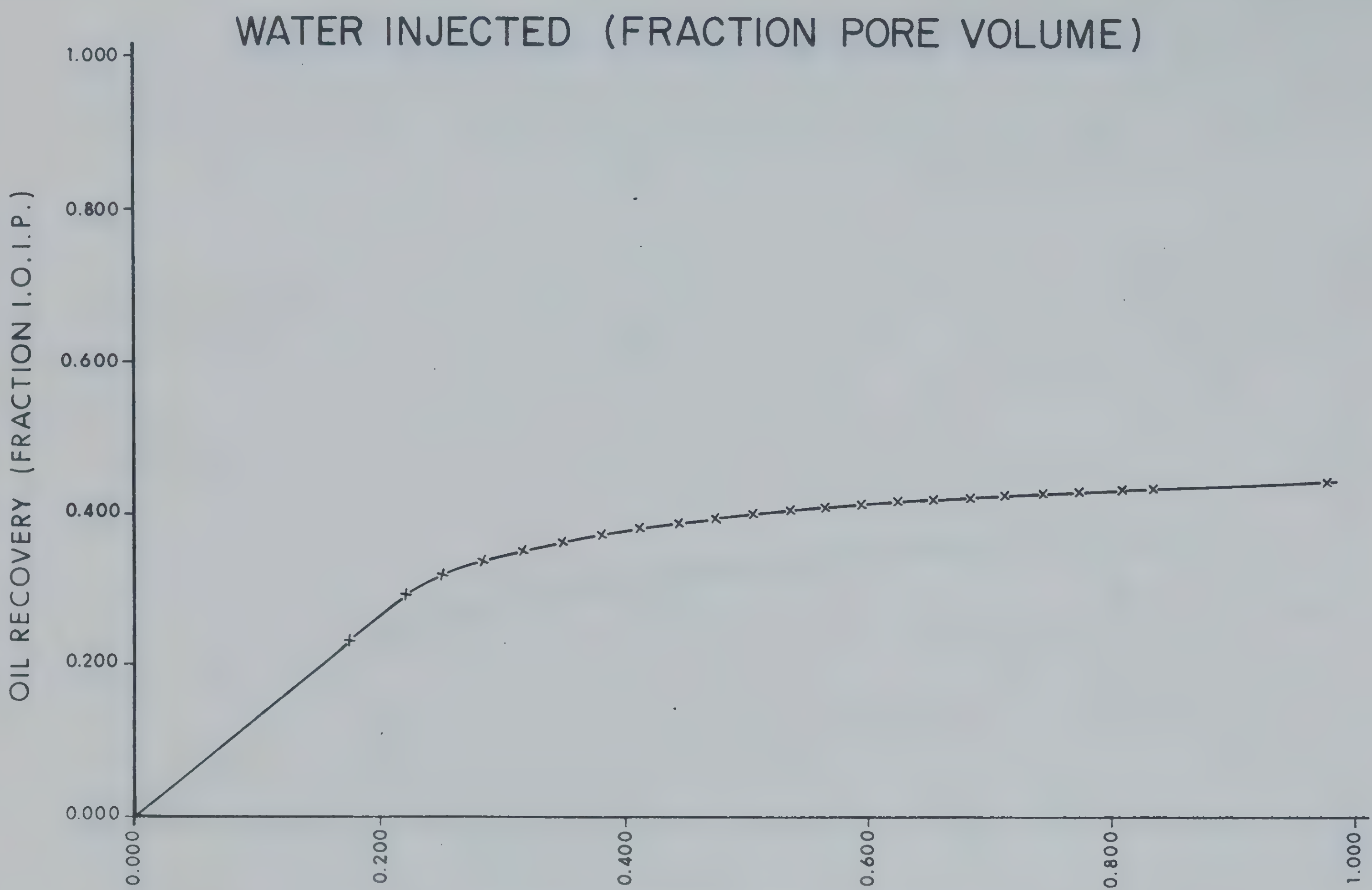


FIGURE C – 9 : DISPLACEMENT TEST RECOVERY–RUN No. 9

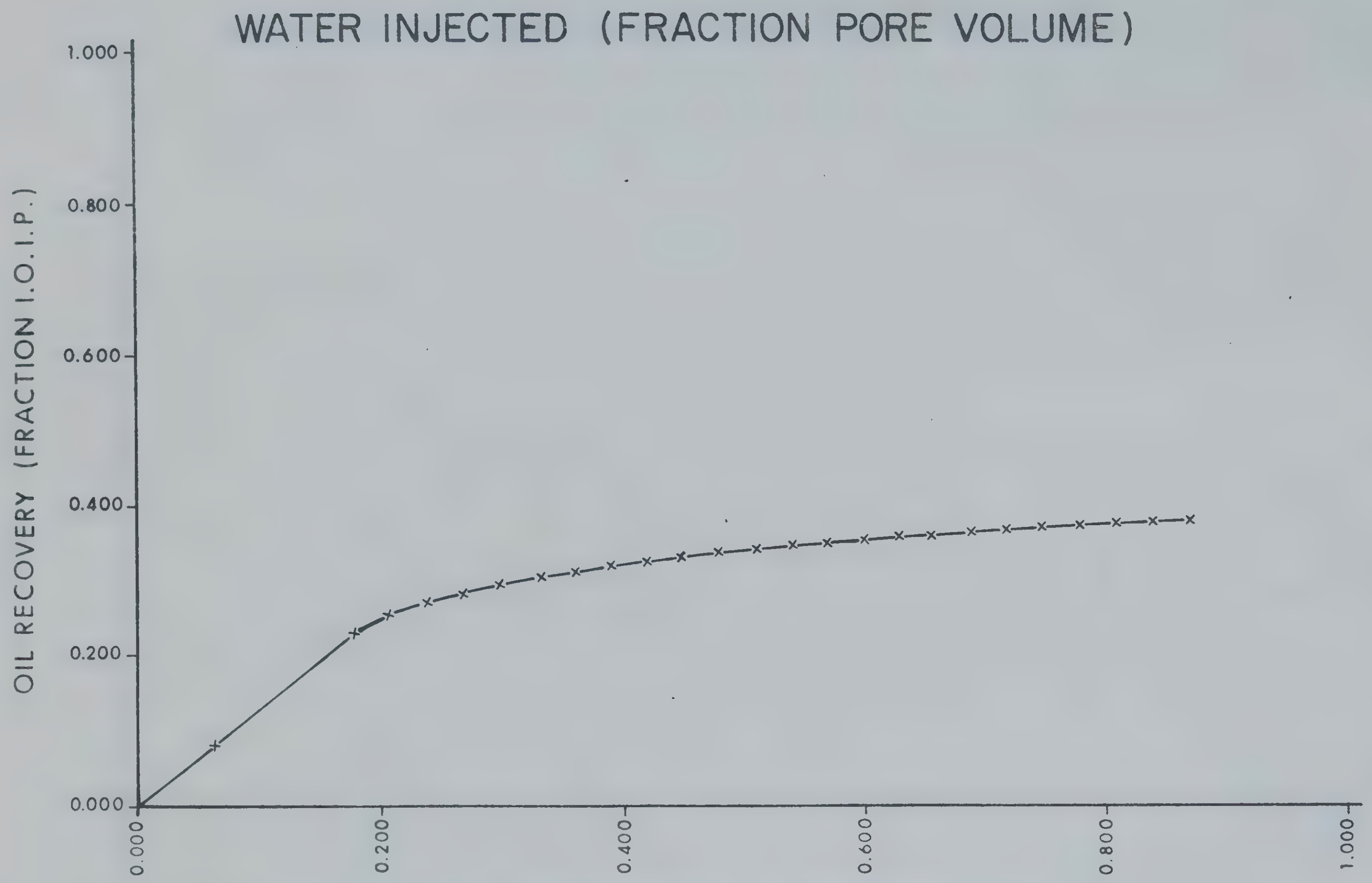


FIGURE C-10 : DISPLACEMENT TEST RECOVERY-RUN No. 10

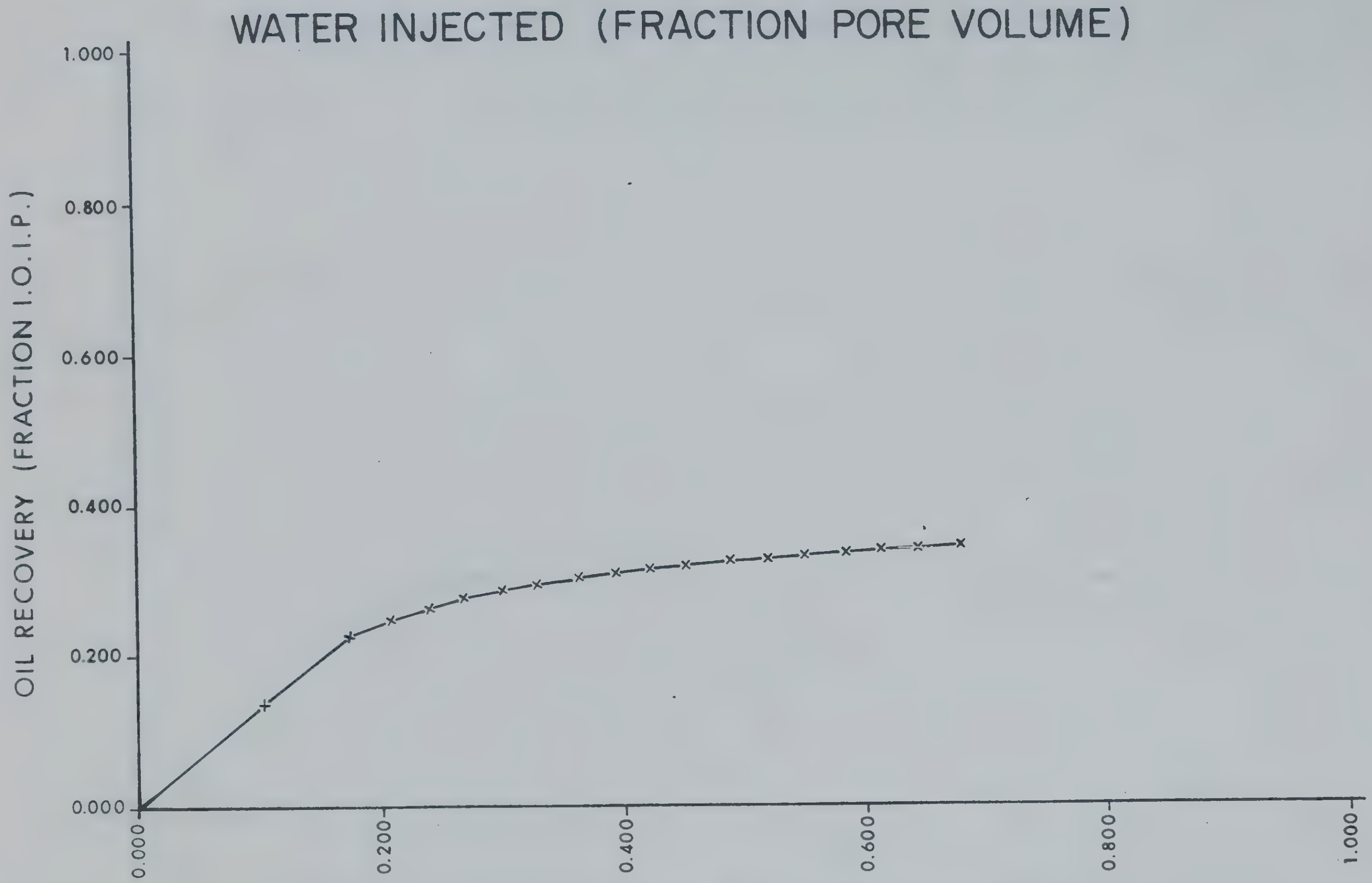


FIGURE C-11 : DISPLACEMENT TEST RECOVERY-RUN No.11

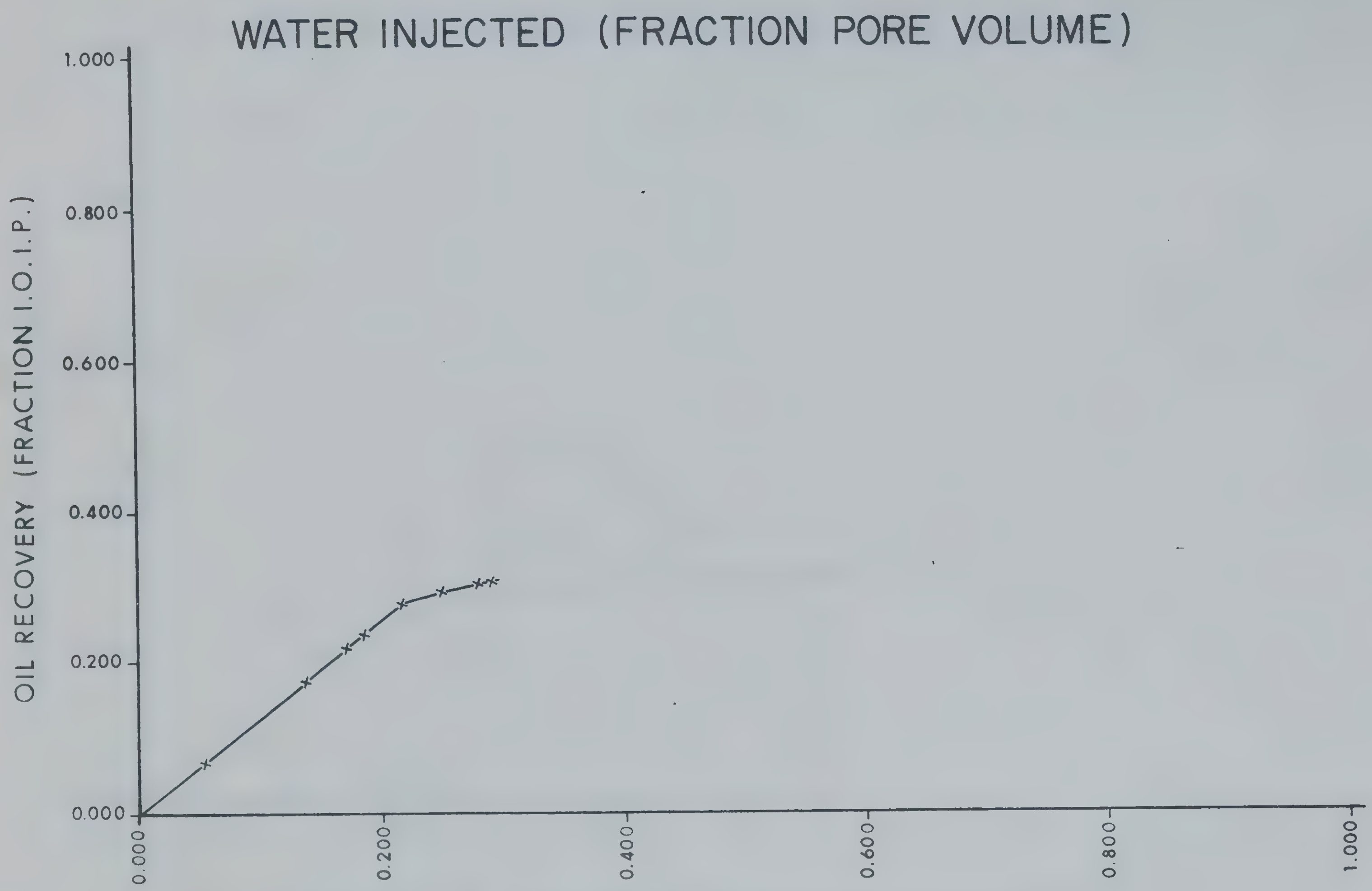


FIGURE C-12 : DISPLACEMENT TEST RECOVERY-RUN No. 12

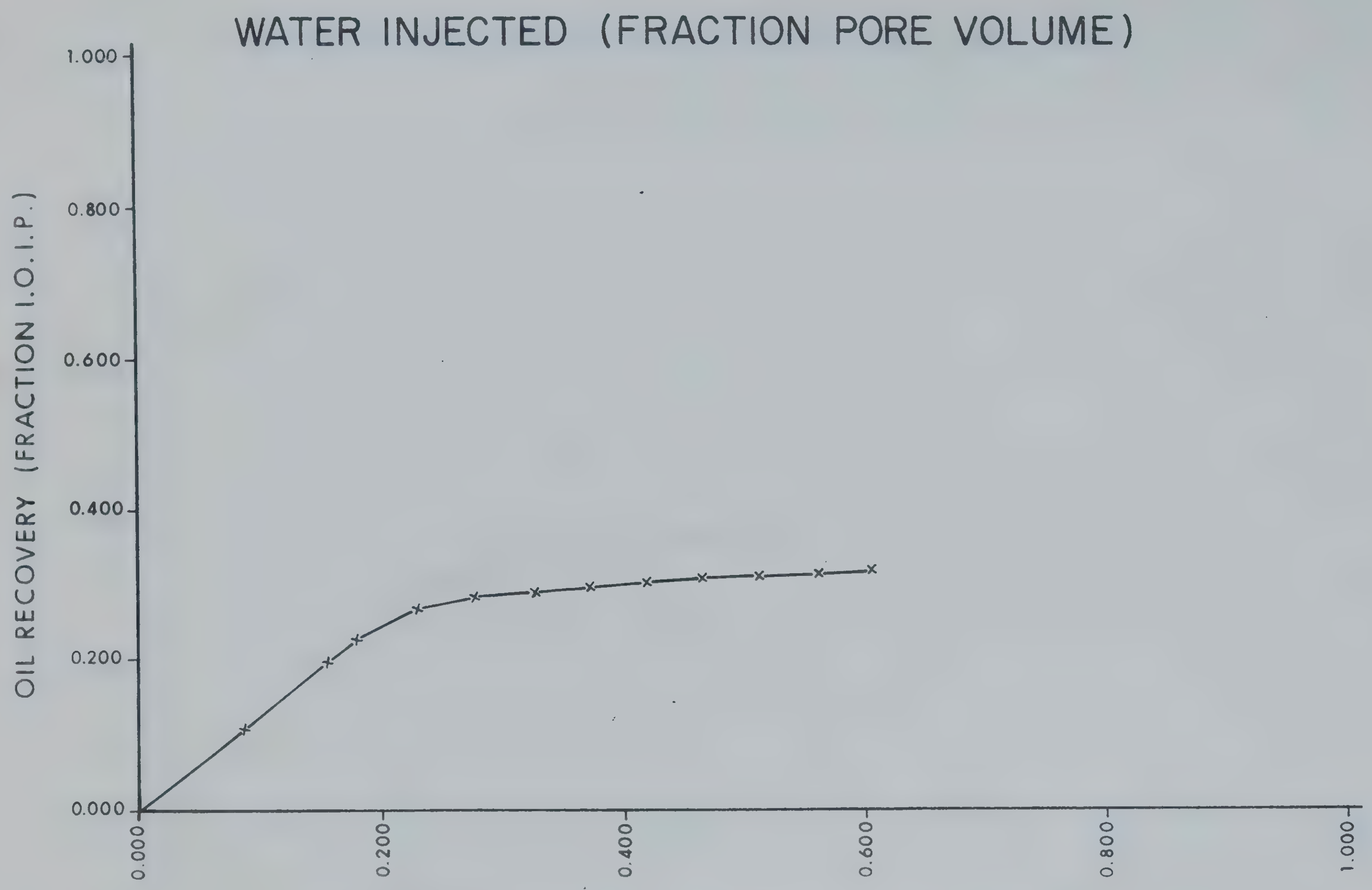


FIGURE C-13 : DISPLACEMENT TEST RECOVERY-RUN No.13

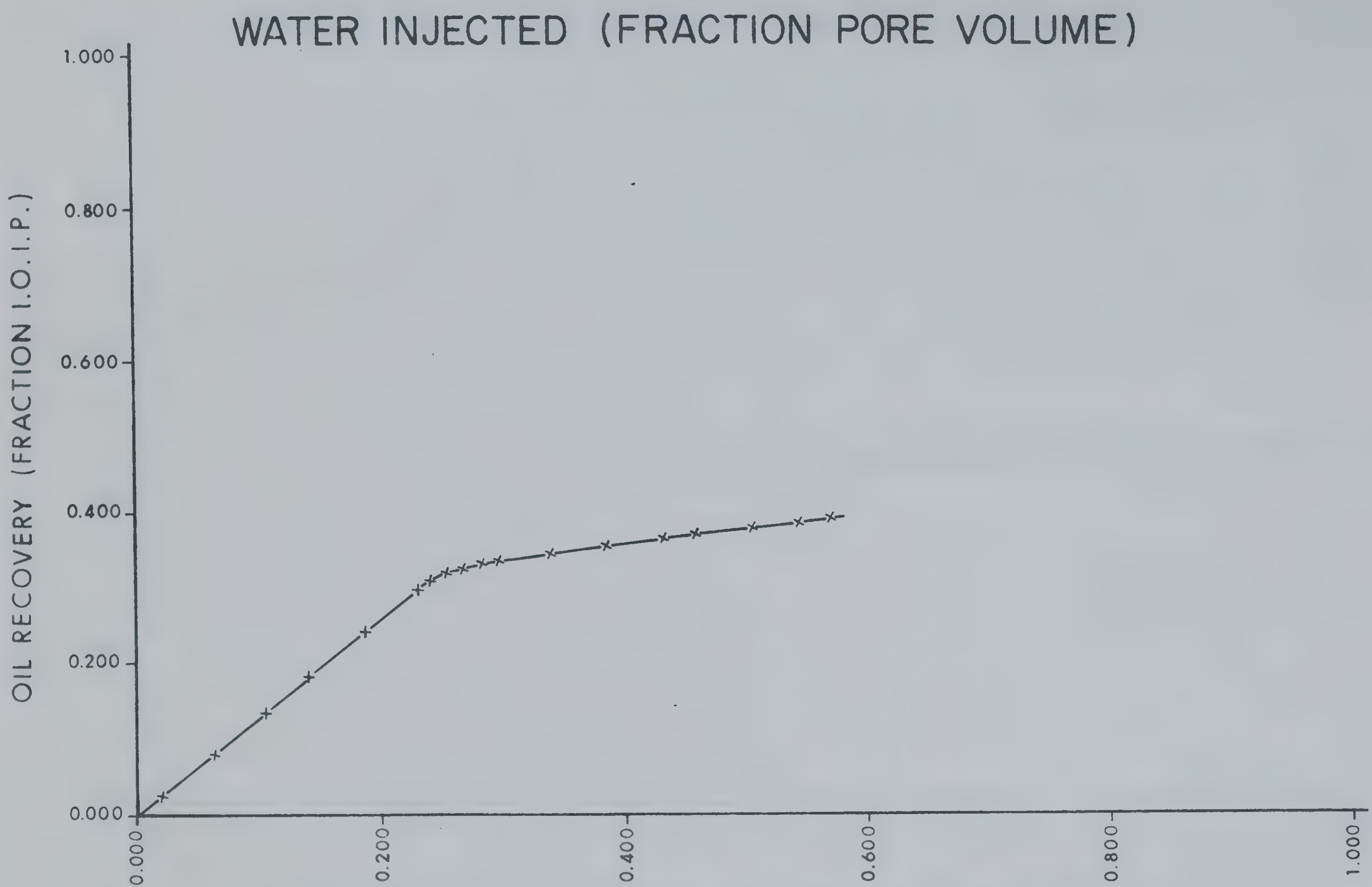


FIGURE C-14 : DISPLACEMENT TEST RECOVERY-RUN No. 14

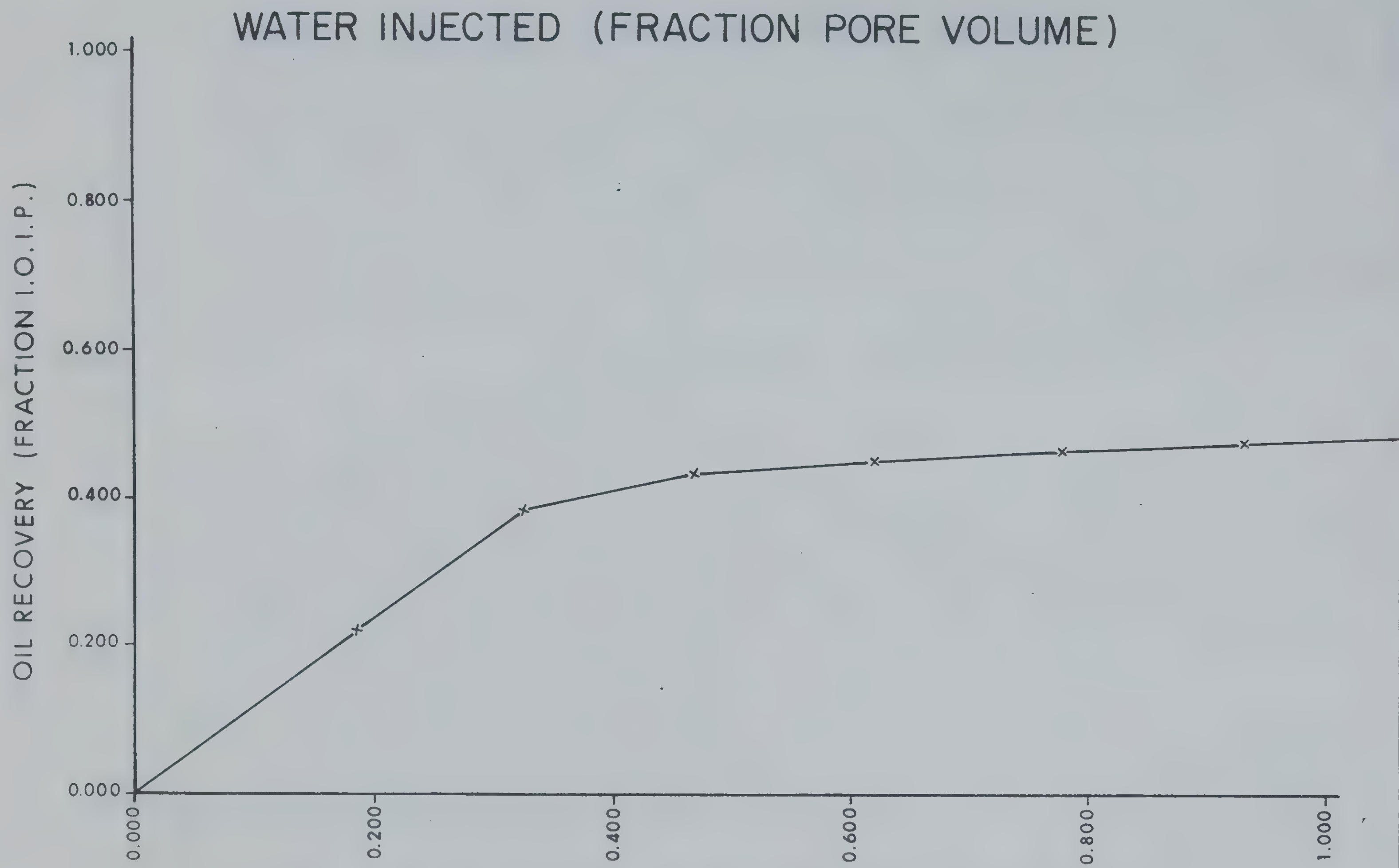


FIGURE C-15 : DISPLACEMENT TEST RECOVERY-RUN No. 16

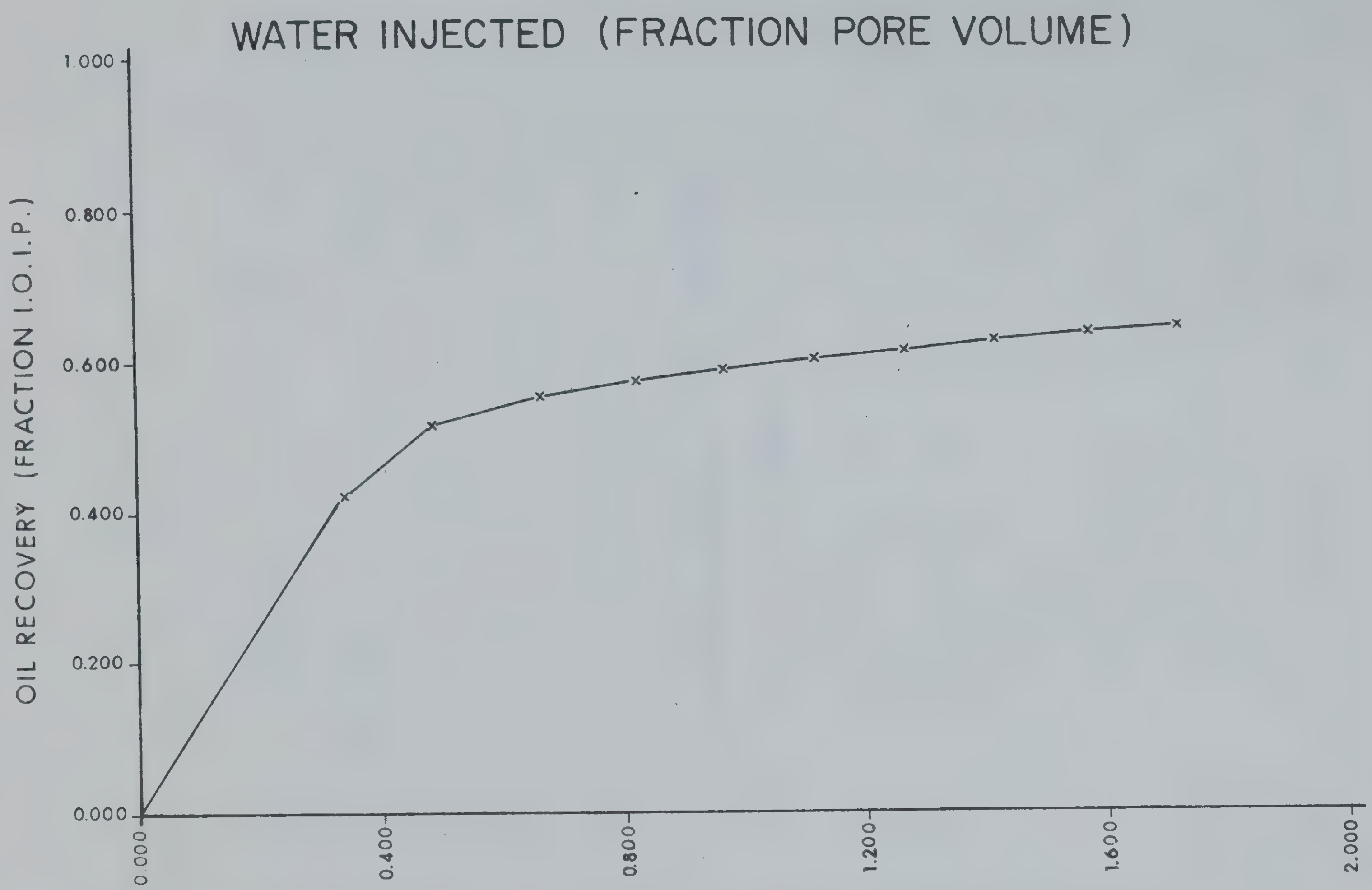


FIGURE C-16 : DISPLACEMENT TEST RECOVERY-RUN No. 17

APPENDIX D

DETERMINATION OF PERMEABILITY RATIOS

DETERMINATION OF PERMEABILITY RATIOS (WELGE METHOD)

Employ the Buckley-Leverett equation under the following assumptions (approach is that proposed by Collins, R.E.)

1) capillary and gravity effects are negligible
2) fluids are immiscible and incompressible
3) the porous media is homogeneous and linear

For a system of length L with $S_w(x,o)=S_c$ introduce a wetting fluid which displaces a non-wetting fluid at a rate q(t) at x=0 for $t > 0$. At x=0 only the wetting fluid is flowing and at x=L both fluids are flowing. At the outflow end the cumulative production of the non-wetting fluid is designated by Q_{nw} and the inflow of wetting fluid is shown by Q, where

$$Q = Q_w + Q_{nw} \qquad \text{D - (1)}$$

At the outflow end

$$F_{nw} = \frac{q_{nw}}{q} = \frac{dQ_{nw}}{dQ} = \left[1 + \frac{K_w \mu_{nw}}{K_{nw} \mu_n}\right]^{-1} \qquad \text{D - (2)}$$

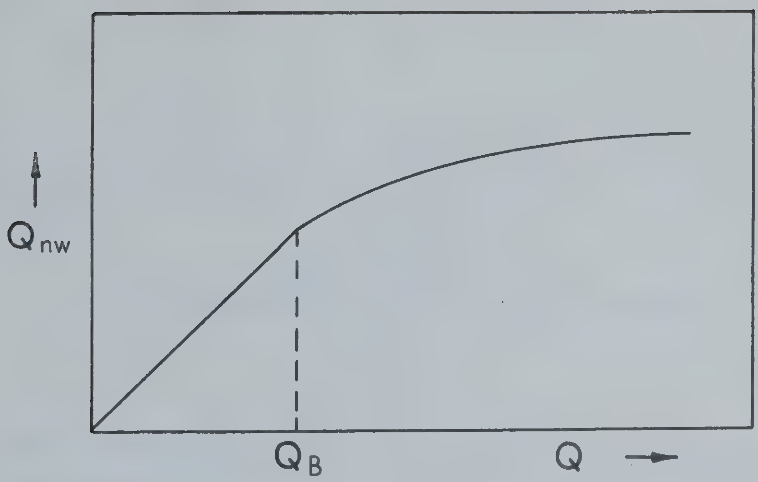
or from the definition of F_{nw}

$$\frac{K_{nw}}{K_w} = \frac{\mu_{nw}}{\mu_w} \left[1 - \frac{dQ_{nw}}{dQ}\right]^{-1} \frac{dQ_{nw}}{dQ} \qquad \text{D - (3)}$$

Welge developed an equation for calculating the non-wetting saturation:

$$S_{nw}(L) = \frac{1}{\phi AL} \left[\phi AL\ (1 - S_c) - Q_{nw} + \frac{QdQ_{nw}}{dQ}\right] \qquad \text{D - (4)}$$

A graph of Q_{nw} versus Q:



shows that from Q = 0 to Q_B the line has a slope of 1 representing a production of oil only. For Q > Q_B, then

$$Q_{nw} = a + b \ln Q \qquad D - (5)$$

for any small segment. By differentiating we find:

$$b = \frac{Q \, dQ_{nw}}{dQ} \qquad D - (6)$$

for each segment. This may be used in equation D-(3) and D-(4) along with the value of Q_{nw} to compute the permeability ratio and its corresponding $S_{nw}(L)$. A sample calculation is shown for run #1 in Table D-1 and graphed in Figure D-1. Points from the relative permeability curve were applied to equation 2 (for the conditions of $\partial P_c/\partial u = 0$ and $\sin\alpha = 0$) to solve for the fractional flow of water at different water saturations (Figure D-2).

From the fractional flow curve a theoretical water breakthrough time (T_B) :

$$T_B = \frac{A \, L \, \phi \, (S_{wa} - S_{wi})}{Q_t} \qquad D - (7)$$

was calculated and the results are tabulated in Table D-2. The

TABLE D-1

SAMPLE RELATIVE PERMEABILITY CALCULATION

RUN #1

From the recovery graph of Oil Produced (Q) and Water Injected (Q_{nw}) the following values of $K_{nw} \setminus K_w$ were obtained:

Q	$\frac{d\,Q_{nw}}{d\,Q}$	S_{nw}	S_w	$\frac{K_{nw}}{K_w}$
1720	.555	.495	.505	.76
1750	.233	.325	.675	.185
1800	.0667	.234	.766	.044
1850	.0333	.216	.784	.021
1900	.025	.211	.789	.016

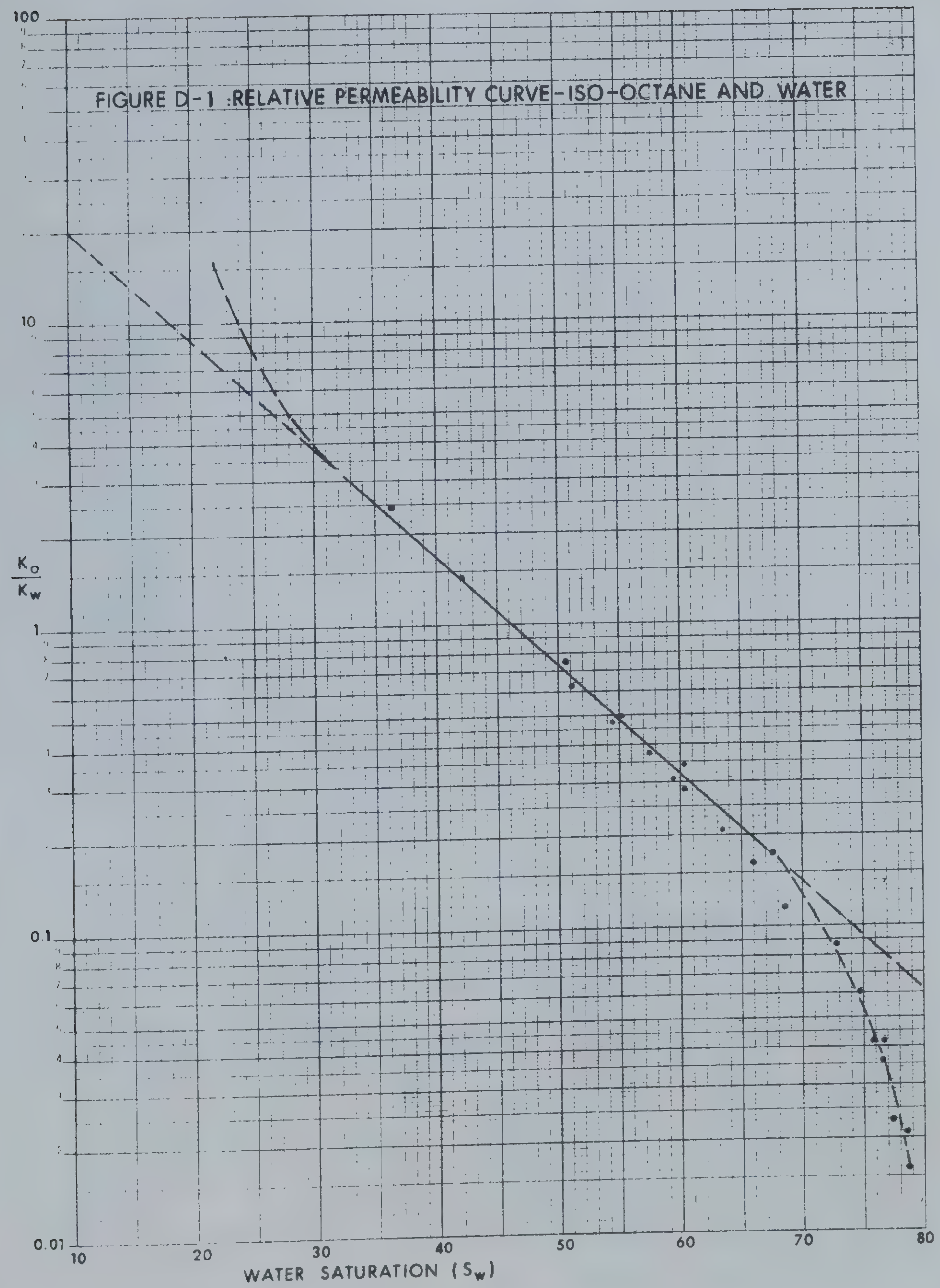


FIGURE D-1 :RELATIVE PERMEABILITY CURVE-ISO-OCTANE AND WATER
100
10
1
0.1
0.01
$\frac{K_o}{K_w}$
10
20
30
40
50
60
70
80
WATER SATURATION (S_w)

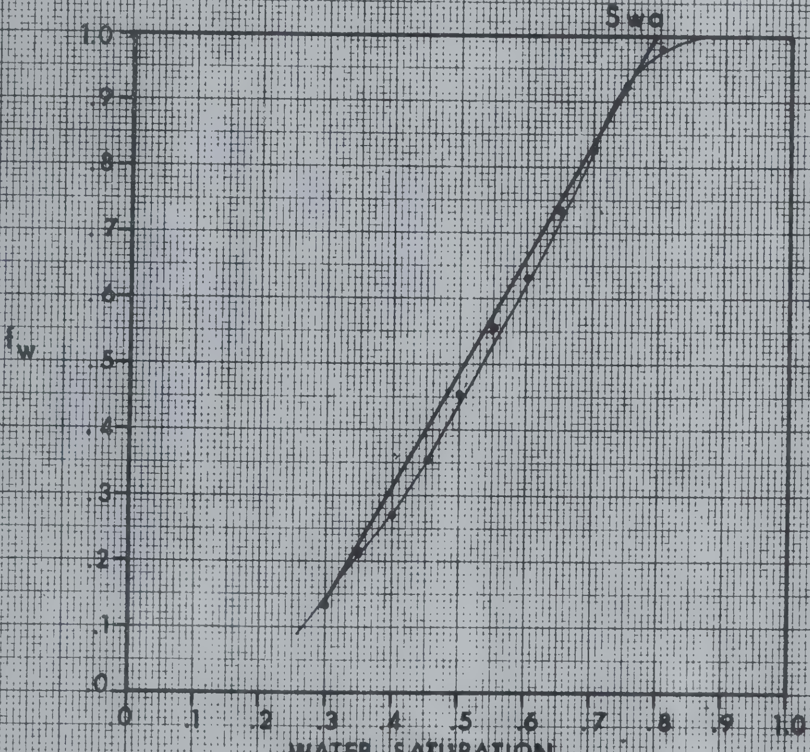


FIGURE D-2: FRACTIONAL FLOW CURVE - ISO-OCTANE

TABLE D-2

BREAKTHROUGH TIME COMPARISONS

RUN	ACTUAL TIME	THEORETICAL TIME	ERROR
1	2 hrs 52 min	2 hrs 46 min	3.5%
3	13 hrs 40 min	13 hrs 38 min	0.2%
4	52 hrs 42 min	57 hrs 36 min	9.0%
5	1 hr 26 min	1 hr 21 min	5.8%

theoretical and observed times for rates of 120 to 1200 cc/hr yielded a maximum deviation of 5.8 percent. However, in the case of run #4 (30 cc/hr) the error increased to 9 percent. This is due to the fact that capillary forces play a dominant role at low rates.